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SUMMARY OF RESPONSES TO JOINT COMMITTEE QUESTIONNAIRE ON POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

PRINTED AT THE REQUEST OF

HENRY M. JACKSON, Chairman
COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

AND

WARREN G. MAGNUSON, Chairman
COMMITTEE ON COMMERCE
UNITED STATES SENATE

PURSUANT TO

S. Res. 45

A NATIONAL FUELS AND ENERGY POLICY STUDY

Serial No. 94–43 (92–133)

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Committee on Interior and Insular Affairs

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SENATE RESOLUTION 45

National Fuels and Energy Policy Study

This publication is printed for the use of Senators participating in the National Fuels and Energy Policy Study, authorized by Senate Resolution 45 of the 92d Congress.

Senate Resolution 45, introduced by Senators Jennings Randolph and Henry M. Jackson, was amended and agreed to by the Senate on May 3, 1971. The resolution authorized the Senate Committee on Interior and Insular Affairs and ex officio members of the Committee on Commerce and Public Works and the Joint Committee on Atomic Energy to make a comprehensive study of programs and policies required to meet national energy needs.

Subsequently, the Senate approved the addition of ex officio members from the Committees on Aeronautical and Space Sciences, on Finance, on Foreign Relations, on Government Operations, and on Labor and Public Welfare.

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MEMORANDUM OF THE CHAIRMAN

To Members and ex-officio members of the National Fuels and Energy Policy Study (S. Res. 45, 92d Cong.), Committee on Interior and Insular Affairs:

This study presents an in-depth analysis of the answers to a questionnaire covering "potential problems associated with the delivery of crude oil from Alaska's North Slope." The questionnaire was sent on August 23, 1976 by Senator Magnuson, Senator Stevenson, and myself to 13 Federal agencies and departments; to the Governors of Alaska, California, and Washington; and to 6 private companies. Copies of the questionnaire were sent at later dates to 4 more private companies. This study includes replies received as of November 1, 1976.

The questionnaire was drafted by members of the Commerce Committee and Interior Committee staffs. This study was prepared for the Committees' use by the Congressional Research Service, Library of Congress, Specialist in Public Utility and Natural Resource Economics.

I believe that the factual information presented will be of great assistance to the Congress and the Nation in our deliberations concerning the most desirable policies to govern the disposition of crude oil from Alaska's North Slope. My colleagues and I appreciate the assistance of those who responded to the questionnaire and those who analyzed the results.

HENRY M. JACKSON, *Chairman.*

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U.S. Senate,
Committee on Interior and Insular Affairs,
Washington, D.C., September 9, 1976.

Dr. Norman Beckman,
Acting Director, Congressional Research Service, Library of Congress, Washington, D.C.

Dear Dr. Beckman: The Senate Committee on Interior and Insular Affairs and the Senate Committee on Commerce recently sent a joint questionnaire concerning potential problems associated with the delivery of crude oil from Alaska's North Slope to various departments and agencies within the Executive branch, the Governors of Alaska, Washington and California, and to a number of private parties who expect to transport some or all of the crude oil from the West Coast inland. Recipients were requested to reply to the questionnaire by September 13.

We have been concerned for some time now about the effect this crude oil will have on the overall West Coast supply and transportation systems. It is fairly clear that adequate planning and preparation have not been undertaken in order to fully accommodate this new domestic oil supply. It appears there is not sufficient demand for that oil on the West Coast; the necessary arrangements have not been made to transport it to either the Northern Tier refineries which will soon lose their source of supply from Canada or to other refineries in the Midwest.

In order to do a proper job of analyzing the responses to the questionnaire we would like to request the assistance of Dr. Douglas N. Jones, Acting Chief of the Economics Division. Dr. Jones and the members of his staff have been of considerable assistance to us in the past on similar efforts and have provided considerable expertise and insight that otherwise would have been lacking in our analytical efforts. Dr. Jones is an expert on the Alaska pipeline in particular and on regulated industries in general and would be of great assistance in this study. One other member of the Economics Division staff, Mr. Larry Kumins, has already been assisting in preparing an introductory chapter for the eventual Committee publication of this study.

As always, we appreciate your continued assistance in our efforts.

With best wishes,

Sincerely,

Warren G. Magnuson, *Chairman.*
Henry M. Jackson, *Chairman.*
Adlai E. Stevenson, *U.S.S.*

LETTER OF TRANSMITTAL

THE LIBRARY OF CONGRESS,
CONGRESSIONAL RESEARCH SERVICE,
Washington, D.C., November 24, 1976.

To: Hon. Adlai E. Stevenson,
(Attention of Leslie Goldman),
Hon. WARREN G. MAGNUSON,
Chairman, Committee on Commerce,
(Attention of Henry Lippek),
Hon. HENRY M. JACKSON,
Chairman, Committee on Interior and Insular Affairs,
(Attention of Betsy Moler),
U.S. Senate Office Building,
Washington, D.C.

DEAR SENATORS STEVENSON, MAGNUSON, AND JACKSON: As you requested we have now completed summarizing the replies you received from your August 1976 joint questionnaire, "Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope." Taken together with your recent hearings and a compendium of the full responses, this report should allow the reader a way of readily coming abreast of the issues and information still surrounding the important policy question of the best routing and disposition of this soon-to-be-available oil from Alaska.

Yours truly,

NORMAN BECKMAN,
Acting Director.

POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

Prepared by Dr. Douglas N. Jones, Lawrence Kumins, Kenneth De Jarnette, Economics Division; John Jimison, Environment and Natural Resources Policy Division; Raymond Celada, American Law Division, November 1976

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INTRODUCTION

This report summarizes the 10 responses received to the Interior and Commerce Committees' August 1976 questionnaire entitled "Potential Problems Associated With the Delivery of Crude Oil From Alaska's North Slope." The summaries are keyed to the many questions posed in that questionnaire which is reproduced as Appendix I. An attempt was also made to indicate to the reader what the importance of a particular question was along with the significance of particular answers.

John Jimison of the Environment and Natural Resources Policy Division prepared sections I andII; Larry Kumins, Kenneth De Jarnette, and Dr. Douglas Jones of the Economics Division prepared sections II, IV, and V, respectively.

Appended to these 5 sections is a memorandum by Raymond Celada of the American Law Division regarding the legal aspects of pipeline rights-of-way and oil exports.

I. West Coast Petroleum Supply

The first set of questions posed by the committees dealt with the supply of crude oil and refined products likely to be available to the West Coast of the United States upon completion of the Alaskan oil pipeline.

A. CRUDE OIL SUPPLY

Three sources of crude oil were examined: Alaska—North Slope, West Coast (PADD V) other than the North Slope, and imports from overseas. The various responses received by the committees which dealt substantively with this topic are summarized for each.

1. Alaska—North Slope

(a) What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska Pipeline?

Without exception, the respondents indicated that crude oil would begin flowing through the pipeline in 1977. Some were willing to be precise, most were not.

Ashland provided a straightforward answer: "July 1, 1977." Three other companies merely indicated "mid 1977."

All the other responses to this question are subordinate to and probably derived from that of the Alyeska Pipeline Service Company, which is building the pipeline and will operate it. Alyeska's "best current estimate" is the summer of 1977 for the first oil deliveries to Valdez, certainly prior to September, and quite possibly in July.

(b) To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

This question refers to charges that a number of welds along the Alyeska pipeline are deficient and were falsely reported to have been adequate. Hearings on the question have been held both in the House of Representatives and the Departmentof Transportation.

Alyeska Pipeline Service Company states that its prediction of first throughput in the summer of 1977 takes into account the weld repair situation. Alyeska states that "of the less than 4.000 welds, some 3.390 have been resolved by repair and other remedial means to this date. We have recently requested exemptions for some 600 relatively inaccessible welds which our fracture mechanics studies have indicated are quite acceptable from the standpoint of strength and integrity" . . . "we feel confident that they will not delay completion of construction of the Pipeline System and delivery of the first crude oil through the system to the terminal at Valdez".[1]

No respondent contradicted Alyeska in its confidence that welding problems would not delay start-up.

Unfortunately, the Department of Transportation which must approve the exceptions, made no substantive response to any portion of the questionnaire, generally deferring to the Federal Energy Administration and its ongoing study of the situation. The FEA study made no reference to the pipeline weld situation.

Despite the optimism of the pipeline company and other respondents, it is not a foregone conclusion that the 600 inaccessible welds will be approved on the basis of a fracture test. Moreover, an investigative report by the staff of the Energy and Power Subcommittee of the House Interstate and Foreign Commerce Committee has alleged that later welds suffered the same defects as the ones currently in question. Alyeska has denied these allegations. Alyeska did not speak to the delays involved if the exceptions applied for are not granted, nor to those implicit in any possible follow-up on the later allegations. Because of the great environmental sensitivity of the oil pipeline routes, it may perhaps be wisest to note, as Sohio alone did, that the continuing investigation and consideration of the welding situation casts some doubt on the scheduled start-up time.

(c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska, and use for pipeline fuel) ?

The respondent's estimates of Alyeska pipeline throughput to 1985 generally followed a uniform forecast. In general, the respondents all anticipated that the pipeline would begin operations in 1977 carrying about 600,000 barrels per day of crude oil, quickly building that total to the level of 1.2 million barrels per day which can currently be carried. All respondents anticipated that level of throughput in early 1978.

Further on, however, the responses diverged. The current consortium agreement of the pipeline's owners holds throughput at that level. Without an amendment to that agreement among the pipeline owners, and some construction of additional compression, the currently au-

[1] As of November 19, 1976, 34 welds remain unrepaired.

thorized throughput of 1.2 million barrels per day will be the maximum. The consensus of the respondents was, however, that the agreement would be modified when required and the compression additions would be made. Significantly, perhaps, Alyeska Pipeline itself did not hazard a prediction of any authorized change in throughput levels.

Of the respondents, those who predicted the earliest increase above the 1.2 million barrel per day throughput were two oil companies, who predicted 1979 throughput of 1.4 and 1.45 million barrels per day. By 1980, however, all respondents except one—government and companies alike—anticipated that Alyeska throughput will be at or approaching the projected MER (maximum efficient rate) of production for the Sadlerochit formation of the Prudhoe Bay field: 1.6 million barrels per day. The one exception is Sohio, which anticipates throughput of 1.2 million barrels per day until 1982, at which point throughput would rise to 2 million barrels per day, assuming the necessary construction, and some additional reserves being dedicated.

TABLE I.—ESTIMATES OF THROUGHPUT OF THE ALYESKA OIL PIPELINE

[Millions of barrels per day]

Respondents	1977	1978	1979	1980	1981	1982	1983	1984	1985
Department of the Interior	0.6	1.2	1.2	1.6	1.6	1.6	1.6	1.6	1.6
Federal Energy Administration:									
Questionnaire		1.2	1.2	1.6	1.6	1.6	1.6	1.6	2.0
Study	.6–1.2	1.3		1.6					2.0
Federal Power Commission	.6	1.2	1.2	1.5	1.5	1.7	1.8	1.8	1.9
State of Alaska	.6–1.2	1.2	1.2+	1.5–1.6		(peaks to 1.8)			
Alyeska Pipeline Service	.6–1.2	1.2	1.2	(1.2 pending amendment of consortium agreement)					
Atlantic Richfield	.6–1.2	1.2	1.4	1.5	1.6	1.6	1.6	1.6	1.6
Exxon	.6	1.2	1.2	1.5	1.5	1.5			
Ashland	.6	1.2	1.4	1.7	1.9	2.0	2.0	2.0	2.0
Sohio (assuming agreement to expand capacity)	.6	1.2	1.2	1.2	1.2	2.0	2.0	2.0	2.0

The 1.6 million barrel per day throughput is anticipated by the Department of the Interior and the Federal Energy Administration's questionnaire response to remain stable until the end of the projected period in 1985, with FEA suggesting an increase in that year alone to 2 million barrels per day.

Two oil companies agreed that the 1.6 million barrels per day level would be maintained, but Ashland (using "publicly available data") joined Sohio in anticipating throughput of 2 million barrels per day in 1982. The Federal Power Commission based its response on a study by DeGolyer and MacNaughton, a well known petroleum consulting firm, performed for Sohio. The FPC's estimates derived from the DeGolyer and MacNaughton study vary from Sohio's own, and anticipate fairly steady increases of production from 1.5 million barrels per day in 1980 to 1.92 in 1985. The State of Alaska suggested that some throughput fluctuation between 1.5 and 1.8 million barrels per day could be expected after 1980, and also noted that any surplus of crude oil developing in the market for Alaskan crude might be reflected in State production controls and diminished pipeline throughput.

No respondent contradicted the general estimation that Alyeskan throughput would exceed 1.6 million barrels per day only if additional oil were found; the projections of quantities above that amount thus suggest the respondents' ideas of the likelihood of additional Alaskan discoveries.

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Despite the variations, the harmony among the estimates from the different respondents is great. The consensus projection might best be stated as follows: .6 million barrels per day initially, rising quickly to the currently agreed 1.2 million barrels per day; rising then to a level equal to optimum production of the Prudhoe Bay field (1.6 million barrels per day) at about the end of the decade; and remaining between that level and the maximum feasible pipeline throughput of 2.0 million barrels per day through the remainder of the period to 1985, depending on the discovery and dedication of additional reserves to the pipeline.

2. West coast production

(a) What is the current production of crude oil in Petroleum Administration for Defense District V?

There was only marginal disagreement about current production of crude oil in PAD District V, and most of that disagreement apparently derived from the time of the report cited (i.e. year end 1975, etc.) rather than actual disagreement about the quantities of oil involved. The highest estimate was that of Sohio and the FPC (again from the DeGolyer and MacNaughton report): 1.076 million barrels per day. The low estimate was that of the Department of the Interior: 1.06. All the estimates given round off to 1.1 million barrels per day.

The FEA study, in its tables of projected crude oil production, cites 1976 production for California and Alaska (Cook Inlet) of 964 and 170, respectively, for a total of 1.134. This total is higher than the next highest estimate by more than 50,000 barrels per day, and more than 60,000 barrels per day higher than the current production reported on the FEA questionnaire response. Whether this figure is based upon actual reports or is a projection in unclear. Whatever the case may be, the current production in the region is roughly 1.1 million barrels per day.

(b) What are your best current projections of production from PAD District V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

No extreme differences in amounts of anticipated crude oil production from PAD District V excluding the North Slope were revealed among the respondents in answer to this question. Only five of eighteen respondents provided quantitative estimates in response to this question. Such entities as the Department of the Interior, the State of California, and Atlantic Richfield were among those not hazarding a guess.

Until 1980, all five submitted estimates are within 100,000 barrels per day of each other. The predicted trends are a matter of interest, however. Exxon and Sohio present the most conservative projections, essentially flat production for the period covered. Ashland foresees moderate growth to a plateau of about 1.4 million barrels per day. The FPC obtains its data again from the DeGolyer and MacNaugton study for Sohio. Oddly, the FPC states in its response to the questionnaire that, "The report indicates that production of crude oil in PADD V other than from North Slope will continue to decline through 1985." In fact, the DeGolyer and MacNaughton study shows steady projected increases (after flat production through 1980) and

is second only to FEA in predicting production expansion to 1.6 million barrels per day by 1985.

The variations in the estimates are largely due to the very rough guesses of new production from offshore fields and other new provinces, rather than a difference of opinion about the production outlook for existing onshore California wells.

TABLE II.—PROJECTED WEST COAST (PADD V) PRODUCTION OTHER THAN NORTH SLOPE

[Millions of barrels per day]

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Federal Energy Administration:									
Questionnaire		1.2		1.3					1.7
Study	1.2	1.2		1.3					1.7
Federal Power Commission	1.1	1.1	1.1	1.1	1.2	1.3	1.4	1.5	1.6
Exxon	1.1	1.1	1.2	1.2	1.2	1.3			
Ashland	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.4
Sohio		1.2–1.4		1.4		1.3			

Note: Estimates rounded to nearest 100,000 bbl/day.

None of the respondents foresees a decline in the production of crude oil in PAD District V other than the North Slope. But there is no agreement as to whether or not a significant increase in non-North Slope PADD V production can be expected. The Pacific ocean floor apparently holds the answer to this question, as new production from Elk Hills will essentially balance declining production from older working fields onshore.

3. Imports

(a) What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content.)

All respondents used data concerning imports produced by the Bureau of Mines of the Department of the Interior from raw data reported by the Bureau of the Census of the Department of Commerce. These data show that for the calendar year 1975, PADD V required 851,000 barrels of crude oil imports per day and 120,000 barrels of petroleum products imports per day. In the first quarter of 1976, the crude oil import total had risen to 867,000 barrels per day, but product imports had dropped 30 percent for a slightly reduced total.

The response of the FEA included information about average sulfur levels. This showed that 600,000 of the 851,000 barrels of crude oil imported daily during 1975 were of less than 1 percent sulfur. The imported crude from the two major countries supplying PAD District V in 1975, Indonesia and Canada, averaged 0.08 percent and 0.28 percent sulfur, respectively, and constituted 54 percent of the daily imports. In its response, Exxon estimated that 65 percent of the crude oil imported was of low sulfur quality; the actual 1975 figure was 70 percent.

The phase down of Canadian crude oil exports is evident in the first quarter of 1976, as Canada sent more than 50,000 barrels per day less to PAD District V than during the calendar year 1975. Saudi Arabian exports rose 50,000 barrels per day, gaining second place to

Indonesia, the most prolific exporter to the U.S. West Coast during both periods.

TABLE III.—CRUDE OIL IMPORTS INTO PAD DISTRICT V, BY COUNTRY OR ORIGIN AND SULFUR CONTENT

[Thousands of barrels per day]

Exporting country	1975 quantity	1st quarter 1976 quantity	Average sulfur content, 1975 (percent)
Indonesia	295.4	392.7	0.1
Saudi Arabia	95.6	146.0	1.7–2.9
Canada	163.6	110.2	.3
Iran	105.2	91.0	1.5
United Arab Emirates	49.9	57.7	1.5
Gabon		18.4	
Ecuador	52.7	16.2	.8
Qatar	10.9	8.4	
Malaysia	5.4	6.7	
Nigeria	13.8	.1	.1
Venezuela	44.1	3.9	1.5

The imports of petroleum products into PAD District V are not as substantial as crude oil imports. Canada led the 1975 exports of products, sending 21,400 barrels per day into the Pacific Northwest. Venezuela, Singapore, the Netherlands Antilles, and the Bahamas were the only other regions of origin sending an average of more than 10,000 barrels per day of products in that year. In the first quarter of 1976, Canada's place as the premier exporter of products to the West Coast was overtaken by an area referred to as the "Hawaii trade zone", which refers to product imports from Hawaii where duties had not previously been paid. The actual country of origin of the crude was not traced. 26,956 barrels per day came from the "Hawaii trade zone", and Canada's shipments were up slightly to 25.297 per day. Again, the Netherlands Antilles, Singapore, and the Bahamas played significant subordinate roles.

(b) What are your best current projections of crude oil and product imports into PAD District V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in Question IV A.)

The only respondent to the questionnaire which fully answered this question with quantitive estimates was Exxon. Estimates for some years were provided by the FEA's questionnaire response, and by the FPC based on Sohio data. The FEA study projects imported quantities of crude oil. As the data in Table IV shows, the estimates of imported crude oil vary.

TABLE IV.—PROJECTED IMPORTS OF CRUDE OIL INTO PAD DISTRICT V

[Thousands of barrels per day]

	1977	1978	1979	1980	1981	1982	1983	1984	1985
1. Federal Energy Administration Questionnaire Study:	[	500			][	300 to 500			]
High case	642	532		500		500			500
Low case	642	532		300		300			300
2. Federal Power Commission		550–650				500			
3. Exxon	800	600	500	600	500	500	400	300	0

There are two basic patterns anticipated. The Federal Energy Administration and Federal Power Commission apparently see an early

diminution of imports due to Alaskan crude oil replacing the higher sulfur imports, but a fairly steady need for low surfur imports until the end of the period in 1985. This continuing need is 500,000 barrels per day without substantial refinery conversion and 300,000 barrels per day even if refineries are converted to process higher sulfur crude oils.

Exxon, on the other hand, sees only gradual replacement of current imports, with quantities declining to a plateau of about 500–600,000 barrels per day in 1980, and then again dropping to zero by 1985. Exxon apparently envisions less early substitution of Alaskan crude oil for imports than FEA, but also less problem in the eventual elimination of all imports, suggesting a greater possibility of refinery conversions.

Since Alaskan oil is lower in sulfur content than approximately 30 percent of the current imports, the apparent projection of continued imports of higher sulfur oil begs for an explanation. Exxon notes only that "the majority" of projected imports "will be low sulfur". In its response, Ashland notes that some minor high-sulfur imports may continue in the face of Alyeska throughout because the North Slope oil is heavy and a light oil may be required, despite sulfur level disadvantages.

Despite the differences in both the early and late years of the period, it should be emphasized that the estimates for the years 1980–1982 are very close. This probably reflects anticipation by all respondents of a time when most high sulfur imports have been replaced, but when continued low sulfur imports are necessary because of the time required and economic factors involved in conversion of refineries to process the sour North Slope crude.

Imports of petroleum products, which showed a 30 percent decline between 1975 and the first quarter of 1976, are also viewed differently by the respondents. Exxon, which predicted a relatively steady decline of crude oil imports, anticipates a stable level of products imports at about 100,000 barrels per day through 1984, and dropping off in 1985. FEA, on the other hand, which predicted fairly stable crude imports, suggests that product imports will continue to decline in the questionnaire response, and does not provide a forecast in the study. No respondent indicated that products imports, currently only a small part of the supply picture, will increase in significance. They are anticipated either to remain at a low level or decline.

TABLE V.—ESTIMATES OF CURRENT REFINERY CAPACITY AND THROUGHPUT IN PAD DISTRICT V

[Millions of barrels per day]

Respondent	Capacity	Throughput	Percent of capacity
Department of Interior	2.5	1.9	76
Federal Energy Administration:			
Questionnaire	2.357	1.98	84
Study	2.357	[1] 2.155, [2] 1.985	91, 84
Federal Power Commission	2.354	1.90	81
Atlantic Richfield	2.7	2.2	81
Exxon	2.305	2.002	87
Ashland	2.588	2.329	90
Sohio	2.4	2.022	84

[1] From study p. 10, table II–2.
[2] From study p. 50, table II–16.

B. REFINERY CAPACITY

This part of the questionnaire follows up on the first part. Once the supply of crude oil from Alaska, the other regions of PAD V, and foreign countries is determined, one must look to the refineries receiving this crude oil and determine the capacity they have to manufacture from it the needed petroleum products. The three questions concerning this topic relate to current refinery capacity and throughput, projections of capacity and throughput, and the capability of the refining capacity to use Alaska crude oil.

1. What is the current refinery capacity and throughput in PADD V?

There was minor disagreement on the current capacity to refine crude oil in PAD District V among the respondents. The data sources varied, and the period of measurement (i.e. calendar year 1975, or Jan. 1, 1976, etc.) differed, leading to estimates ranging from a high of 2.7 million barrels per day of capacity (Atlantic Richfield) to a low of 2.305 million barrels per day (Exxon). A difference of 400,000 barrels per day is significant.

The throughput estimates vary similarly, from a low estimate of 1.9 million barrels per day from the Department of the Interior and the FPC to 2.3 from Ashland oil—also a 400,000 barrel per day discrepancy. It is possible that much of the discrepancy is related to input of natural gas liquids and condensates in West Coast refineries which may or may not have been treated as crude oil throughput by respondents. Yet this difference apparently only accounts for about 170,000 barrels per day, judging from the FEA study, and the high and low estimates of capacity were made by different respondents than the high and low estimates of throughput.

The calculated percent of refinery capacity utilized thus varies from a low of 76 percent in the Department of the Interior estimate, to a high of 90 percent in the judgment of Ashland. Ashland cites FEA as the source of its data, but the FEA's own questionnaire response suggests 84 percent refinery utilization.

The most reasonable conclusion that can be drawn from the responses are that current refinery capacity is probably about 2.4 million barrels per day and current throughput is probably about 2.1 million barrels per day, selecting the median estimates, but that there is some flexibility in both quantities.

2. What are your best current projections for refinery capacity and throughput in PAD District V for each year through 1985?

The projections provided of refinery capacity and throughput did not exhibit any enormous discrepancies. In general, the respondents anticipated that the capacity of PAD District V refineries will rise to about 2.9 million barrels per day and hold that level until 1980–82, and that throughput will reach a total of about 2.6 million barrels per day during the same period.

TABLE VI.—PROJECTION OF REFINING CAPACITY (RC) AND THROUGHPUT (T) IN PAD DISTRICT V

[Millions of barrels per day]

Respondents	1977		1978		1979		1980		1981		1982		1983		1984		1985	
	RC	T	RC	T	RC	T	RC	T	RC	T	RC	T	RC	T	RC	T	RC	T
Department of the Interior	2.8	-----	2.9	-----	2.9	-----	2.9	-----										
Federal Energy Administration	2.8	2.1	2.9	-----	2.9	-----	2.9	2.3										2.9
Federal Power Commission			2.8	2.5							3.1	2.8						
Sohio			2.8	2.4			2.8	2.5										
Exxon	2.8	2.5	2.8	2.6	2.9	2.6	2.9	2.6	2.9	2.6	2.9	2.7	3.1	2.9	3.4	3.1	3.5	3.2
Ashland	2.8	2.5	2.9	2.6	2.9	2.6	3.0	2.6	3.0	2.7	3.1	2.8	3.1	2.8	3.2	2.9	3.2	2.9

Only Exxon and Ashland provide numerical estimates beyond 1982, which reveal differing interpretations of the capacity and throughput developments during that part of the prediction period. Exxon foresees continued growth; Ashland projects relatively flat capacity and throughput.

3. What part of the current and projected PAD District V refinery capacity is capable of processing Alaskan crude oil or crude oil of similar grade?

The only respondent to provide substantive estimates in response to this question was Ashland oil, citing data obtained "informally" from FEA, data that appears in neither FEA's own response to the questionnaire nor in the FEA Study. For the FEA study, unsuccessful attempts were made to obtain data from individual companies and refineries, and a computer model was then used to simulate the use of Alaskan-type crude oil in West coast refineries at various prices. The summary chart from this model plots usage of Alaskan crude at various prices, and indicates that at prices of less than about $11.50 per barrel delivered, about 1.05 million barrels per day would be used of the 1.2 million barrels per day of North Slope production. This suggests complete replacement of all other similar crudes and a total capacity to use such sour crudes of 1.05 million barrels per day.

The Department of the Interior estimated that 65% of current refinery capacity was capable of processing sour crude. Given Interior's estimate of current refinery capacity at 2.5 million barrels per day, this suggests current sour crude refinery capacity of 1.625 million barrels per day.

In its questionnaire response, FEA includes a 1975 table showing 1.892 million barrels per day of capacity in "refineries likely to utilize North slope crude."

The changes from the current capability to refine sour crude are likely to depend on the relative cost of Alaskan crude and on the ability to pass refinery modification costs through to customers. Unless Alaskan crude has a price advantage and conversion costs can be recovered, it is unlikely that refineries will be modified to accept the higher sulfur crude.

The Ashland estimates obtained "verbally" from FEA are as follows:

[Millions of barrels per day]

Year	PADD V		
	Total capacity	Sour crude capacity	Percent of total
1976	2.588	1.692	59.1
1977	2.835	1.914	65.4
1978	2.874	1.956	67.5
1979	2.906	1.984	68.1
1980	2.938	2.012	68.3
1981	2.996	2.052	68.5
1982	3.056	2.093	68.5
1983	3.118	2.136	68.5
1984	3.186	2.178	68.5
1985	3.243	2.221	68.5

The other current estimates noted above can be compared with the 1976 report in this data series to provide some indication of whether Ashland's projected capacities are reasonable. If the percent of capacity that is capable of using sour crude is accurate in the Ashland series (and it does agree with the Department of the Interior's estimate), then the projected refinery capacities (Table VI) can be multiplied by approximately 65% to determine sour crude capacity.

Although most respondents did not respond to this question adequately, estimates can be derived from information provided in response to other questions which are perhaps as reliable as can be expected without having access to individual refinery plans. The capacity to use sour crude oil in West Coast refineries is a factor highly sensitive to delivered prices and other factors.

II. West Coast Petroleum Demand

A. What is the current demand for crude oil and refined petroleum products in PADD V?

B. What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

The aggregate level of PADD V demand for oil products is a variable with widespread impact on the economics of Alaskan oil. Because transport facilities to other PADD's are not currently extant or are very exepnsive, a localized surplus will occur if PADD V demand falls far below pre-Embargo expectations. Obviously the extent of a surplus is in part a function of West Coast demand, and the determination of this latter is the point of the question.

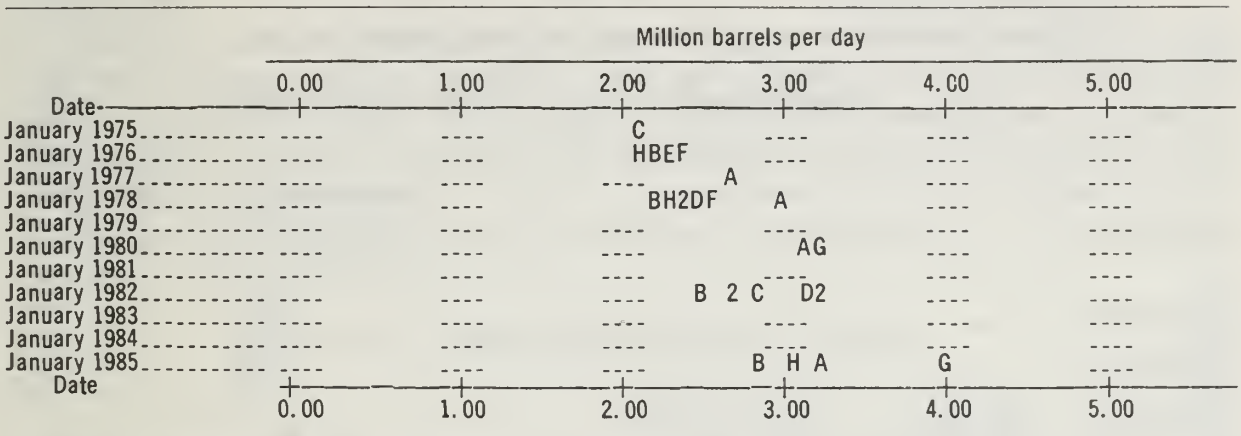
The FEA paper submitted in response to the questionnaire cites an Interior Department communication to Congress of April 4, 1973, which characterizes pre-Embargo forecast levels for PADD V product demand. At that time, Interior predicted West Coast demand would be 3.315 mbd in 1980 and 4.052 mbd in 1985. At these demand levels, a PADD V shortage of nearly one mbd was forecast, leading Interior to state:

> Obviously, all Alaskan oil can be consumed on the West Coast, taking the place of foreign oil that would have to be imported. There is no indication of any export of Alaskan oil.

FIGURE 1

SUMMARY OF PETROLEUM DEMAND ESTIMATES BY CERTAIN COMPANIES AND AGENCIES RESPONDING TO QUESTION NO. II

[A—FPC; B—FEA; C—Sohio1, lower bound; D—Sohio2, upper bound; E—Arco1, lower bound; F—Arco2, upper bound; G—Interior, 1973; H—Ashland]



Source: Responses to question No. II, and CRS estimates. N.B. the digit 2 indicates 2 data points falling on the same spot.

Responses to Question II from both the companies and the agencies frame up current thinking. The range of responses is displayed in Figure 1, along with the Department of the Interior's 1973 estimates for comparison. Because the key variable is aggregate end user demand, and this ultimately determines crude demand, we have focused attention on product demand in the summary chart, especially 1978 and 1982, which represent milestones at which time TAPS throughput is expected to reach 1.2 mbd and 2.0 mbd respectively.

Figure 1 shows how the respondents' overall oil product demand estimates diverge, or fan out from, present consumption levels over time. It also portrays FEA's forecasts as the lower bound of current thought on PADD V demand, with FPC/Pace at the upper end. Of further note is the 1973 Interior estimates, which fall above highest 1976 vintage forecasts.

The matter of a PADD V surplus and West Coast demand also has an impact on the economics of Alaska crude production. If there is inadequate PADD V demand, this oil will have to be sold in more distant markets (or shut in). Transport to them, by whatever means, will be more costly than transport within PADD V, and this will mean lower wellhead net backs for producers and royalty owners in Alaska. This phenomenon will occur as Alaskan crude competes with other crudes at distant locations, given the fact that foreign crude most likely will have lower transport costs. In order to be price competitive, given high transport costs, wellhead prices will have to be backed off to the point that the total delivered cost of Alaskan crude (i.e., crude plus transport) will equal that of competitive imports from elsewhere.

Turning to the content of particular responses, the FPC reply to Question II draws on a Pace Company study done for SOHIO. The Pace study is based on an average 3.6 percent per annum product demand growth rate. Table 1 shows how this plays out over the time frame of interest. Within the 1972–1995 period of the forecast, this 3.6 percent average growth rate varies from subperiod to subperiod. Their projections are not a simple straight line. Rather, they are based upon an analysis of demand for fuel in six consuming sectors, under

a "most probable" scenario which includes the influence of these important factors on aggregate PADD V energy demand:

—Relatively rapid growth of nuclear power.

—Alaskan LNG imports to California savings 653,000 b/d of oil, in the early 1980's.

—Various gasoline saving trends in the auto sector.

TABLE 1.—PACE/FPC ESTIMATE OF PADD V REFINED PRODUCT DEMAND

Year	Demand (thousand barrels per day)	Growth rate from 1975 (percent per year)
1977	2,895	14.4
1978 (estimate)	3,010	10.8
1980	3,251	8.0
1982 (estimate)	3,300	5.9
1985	3,339	4.2

Source: Pace Study with CRS interpolations.

We have interpolated 1978 and 1982 as milestone year figures to dovetail with anticipated throughput changes.

FEA responded to the request for information with a study of great detail and substance. Various parts of the report (entitled North Slope Crude—Where To?—How?) address Questions A and B and the relevant material is summarized below. Their response to the inquiry was not explicitly keyed to the questionnaire, so we have imputed answers to the questions based on material contained in the text.

FEA report is marred, as far as Question II is concerned, by an apparent error wherein its 2.287 mbd product and 2,383 mbd crude demand estimates are alternately cited as applying to the year 1978 (page 52 and figure 13 on page 128) and 1980 (In tables II–13 and II–14). It appears that these figures apply to 1978, although this is uncertain. Nevertheless, Table 2 embodies this interpretation of what FEA intended. It appears that product demand figures come from unpublished FEA data in the National Energy Outlook Data Base.

TABLE 2.—FEA'S IMPUTED RESPONSE TO QUESTION 2

Year	Product demand (thousand barrels per day)	Growth rate from 1975 (percent per year)	Crude demand (thousand barrels per day)
1976	2,311	4.5	2,056
1978 (?)	2,383	2.5	2,287
1982 (estimate)	2,600	2.3	2,530
1985	2,966	3.0	2,875

Source: FEA report with CRS interpolations.

We have interpolated data for the milestone year 1982, based on the 1978–1985 growth rate of 2.2 percent per annum for products and 2.6 percent per annum for crude. The differential between these growth rates indicates an implicit belief that some refined product imports to PADD V will be replaced by material refined within the district itself.

The FEA study (Chapter II, Section E) contains a rather sophisticated treatment of the components of product demand. This is a note-

worthy exercise which includes a refinery-by-refinery capability survey and other considerations. Its orientation is more toward estimating the PADD V surplus and is therefore considered in the Question II response analysis. It does, however, support FEA's crude oil demand estimates.

SOHIO's basic demand projection assumes what may well be a high 5.5 percent per annum growth rate in product demand during the 1975–1978 time frame. Thereafter, SOHIO forecasts growth declining to the 4–5 percent yearly rate, although they note that this is subject to many vicissitudes. Table 3 reproduces SOHIO's demand estimates for the milestone years, as well as the total amount of percentage increase above 1975 level.

TABLE 3.—SUMMARY OF SOHIO RESPONSE TO QUESTION II

Year	Product demand (thousand barrels per day)	Growth rate from 1975 (percent per year)	Crude demand (thousand barrels per day)
1975	2, 211		
1978	2, 500–2, 600	4. 2–5. 5	2, 300–2, 400
1982	2, 500–3, 200	4. 0–5. 5	2, 670–2, 940

Source: Sohio response.

Crude demand is estimated by SOHIO at 92 percent of refined product demand, and tabulated in Table 3.

The upper end 1982 forecast embodies both a rather large aggregate increase from 1975, as well as a substantial 300,000 b/d margin of error relative to the lower end estimate.

Of note in the SOHIO forecast is a much greater growth in the demand for residual fuel than for lighter products. Another consideration is the apparent assumption that refined product imports will continue to grow in absolute terms and continue to constitute 8 percent of oil product consumption.

Arco's response, which is summarized in Table 4 mentions the speculative risks involved in making demand forecasts. A 3–5 percent annual growth rate is indicated for the 1976–85 time frame, although the response itself does not contain specific demand figures.

TABLE 4.—ARCO RESPONSE TO QUESTION II

Year	Product demand (thousand barrels per day)	Growth rate (percent per year)	Crude demand (thousand barrels per day)
1976	2, 400–2, 500		2, 200
1978	2, 550–2, 760	3–5	2, 330–2, 425
1982	2, 870–3, 350	3–5	2, 625–2, 950

Source: Estimated from Arco response.

As with SOHIO, proportional increases in product imports (and refinery gains) are implicit in the Arco forecast.

Ashland responded with the product demand figures in Table 5, which embody a 4 percent annual growth rate. By 1978, they forecast PADD V demand to be 11.8 percent over 1975 levels (3.8 percent

annual growth). In 1982, it is predicted to be 28.5 percent above (about 3.7 percent annual growth) 1975 levels.

TABLE 5.—*Ashland response to question II*

	Barrels per day
1975	2,211,000
1976	2,295,000
1977	2,382,000
1978	2,472,000
1979	2,567,000
1980	2,664,000
1981	2,752,000
1982	2,842,000
1983	2,936,000
1984	3,033,000
1985	3,134,000

Source: Ashland response.

III. West Coast Surplus

This question asks respondents to compare their estimates of crude oil supply in part I with their estimates of demand in part II to determine the size and characteristics of any surplus of crude oil that might occur in PAD District V when the Alaskan pipeline is fully operative.

A. What are your best current estimates of the PAD District V net surplus or deficit of crude oil for each year through 1985 (i.e., the difference between total PAD District V production and refinery runs plus addition to stocks)?

The verdict of the respondents to this questionnaire as well as the judgment reached by all contributors to the FEA study is that a surplus of crude oil will develop on the West Coast shortly after the Alaskan pipeline commences full deliveries. This surplus is foreseen as early as 1977 by Exxon at a level of 200,000 barrels per day, and is predicted to occur by all respondents except Ashland by 1978. The initial surplus estimates range from 200,000 barrels per day to 600,000 barrels per day, with most of them on the high side of the range. Ashland, which anticipates a 199,000 barrel per day *deficit* in 1978 foresees a reversal of that situation by 1979.

From its inception into the next decade, most observers expect the surplus to grow, with possible excesses of supply in the range of 1.1 million barrels per day in 1980, and the preponderance of the estimates at about 700,000 barrels per day. Atlantic Richfield alone envisions a possible supply and demand scenario which may not include a surplus, but Arco also agrees that a surplus is highly probable.

By 1985, the range of possible situations is estimated to be from a deficit of 700,000 barrels to a surplus of 2,000,000, both Atlantic Richfield estimates, with the preponderance of the guesses falling someplace between 600,000 and 1,400,000 barrels per day. The softness in these estimates is illustrated by the almost 800,000 barrel per day dif-

ference between the 1985 estimate submitted by Exxon to FEA and the Exxon estimate for the same year submitted in answer to the questionnaire. Ashland sees the surplus beginning to shrink after 1982, while all other parties anticipate growth except Standard Oil of California which anticipates no change in the level of the surplus.

In light of the various estimates, it seems safe to conclude that a surplus will emerge shortly after the Alaska pipeline begins operations, that it will grow for several years and reach a level of at least 600,000 barrels per day, and that its actual dimensions depend markedly on a number of factors which cannot be precisely foreseen.

B. What are your best current estimates of the PAD District V net surplus of deficit of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PAD District V production and refinery runs plus additions to stocks of such crude oil) ?

Only three respondents to the questionnaire were willing to venture a prognosis on the characteristics of the surplus crude, and none of the three employed any quantification. Sohio bluntly assumed that all of the surplus would be of the heavier, higher sulfur Alaskan-type crude oil. Exxon believed that "in the near term the surplus will be a crude with greater than .5% wt. sulfur," a description fitting not only the Alaskan crude but much of California production and imported crude oil as well.

The FEA questionnaire response cited three reasons for believing that the crude oil that will be surplus to the PAD District V demand will be Alaskan-type crude:

1. The demand for "heavy" products such as residual oil is not great in PAD District V, and refining of the heavy Alaskan crude yields substantial quantities of those products.

2. Alaskan crude will be competing with more local California and Elk Hills crudes which are currently being run, rather than with the bulk of ongoing imports, which are of different characteristics.

3. The lighter, sweeter crude oils required by some refineries will continue to be imported.

The major determinant of whether North Slope crude will be the surplus crude is its selling price. If the price of Alaskan crude is low enough, refineries will have the incentive to modify their refineries to handle it and will prefer purchases of it to higher priced crudes that hurt their competitive positions in product sales. It is unlikely that sellers of the Alaskan crude would follow this option if a market price could be obtained elsewhere.

In summary, it is likely that the great quantities of North Slope crude oil piped across Alaska and tanked to the West Coast would arrive there to find no demand at world market prices. They would be in surplus, if there were no means or permission for delivery elsewhere, and no curtailment of production to prevent such a surplus.

TABLE VII.—ESTIMATED WEST COAST SURPLUS OR DEFICIT OF CRUDE OIL

[Thousands of barrels per day]

Respondent	1977	1978	1979	1980	1981	1982	1983	1984	1985
Federal Energy Administration:									
Questionnaire		600		900–1,100					700–1,300
Study:									
FEA conclusion		600		900–1,100					700–1,300
Exxon submission		552		697					1,797
AD Little "Best" submission				689					805–1,395
California Standard submission				600					600
Atlantic Richfield submission		300–400		500–600					850
Federal Power Commission (from Sohio data)		300–600				750–900			
Atlantic Richfield:									
"Best guess"		400	400	400	400	550	600	650	700
High case		400	400	400	500	700	1,100	1,500	2,000
Low case		200	0	0	0	−200	−400	−500	−700
Exxon	200	600	500	700	600	600	800	900	1,000
Ashland	−815	−199	68	359	523	638	553	518	434
Sohio		300–600				600–800			

IV. Proposed Responses to the Projected West Coast Surplus

Question IV attempts to determine the most promising ways to deal with the excess Alaskan North Slope crude expected to arrive on the West Coast in surplus quantities estimated to be between 300,000 and 1 million barrels per day. The question also indirectly addresses the shortfall of crude in the midwest, principally in the Chicago refinery region.

Alternatives considered by the questionnaire and responses thereto include the following options. (The accompanying may illustrate the major alternative transport routes.)

—Construction of a (Transprovincial) pipeline from Kitimat, British Columbia, to Edmonton, Alberta to connect with existing Canadian and U.S. pipelines to Anacortes, Washington, Billings, Montana and Clearbrook, Minnesota. Oil would be shipped from Valdez to Kitimat via large tankers. Port of Kitimat would have to be developed and about 800 miles of pipeline constructed.

—Construction of a (Northern Tier) pipeline from Port Angeles, Washington to Clearbrook, Minnesota, totally through U.S. territory and utilizing existing railroad rights-of-way over about 25 percent of the distance. Oil to be delivered to Port Angeles from Valdez by tankers.
—Modification and extension of an existing natural gas pipeline to permit oil to be piped from Long Beach, California to Midland, Texas. Oil to arrive at Long Beach from Valdez via tanker. This is called the SOHIO, Midcontinent or El Paso pipeline proposal.
—Use of large tankers from Valdez to Gulf port refineries via Cape Horn, and very large tankers to Freeport, Bahamas for transloading into smaller tankers to Atlantic Coast ports.
—Use of smaller tankers through the Panama Canal.
—Use of large tankers to the western entrance of the Panama Canal for transloading (lightering) into smaller tankers for Canal passage.
—Use of large tankers to the Panama Canal for transfer to existing parallel (U.S. Navy) pipelines and reloading into tankers at the eastern end to Gulf port refineries.
—Construction of a Central American pipeline across Guatemala.
—Use of very large tankers (with icebreakers) via the Northwest Passage to eastern ports, bypassing TAPS.
—Use of tank car unit trains on a contract basis via various western (U.S.) railroads.
—Trading oil with contiguous (Canada and Mexico) or non-contiguous (Japan) foreign countries or a combination thereof.
—Increasing the refining and storage capacities for high sulphur crude in California (PADD V).
—Desulphurizing Alaskan crude at Valdez or elsewhere to permit processing at refineries lacking adquate on line capacity to handle high sulphur crude.
—Cutting back the amount of crude flowing from Alaska to coincide with West Coast demand (called "shutting in of production" in the questionnaire).

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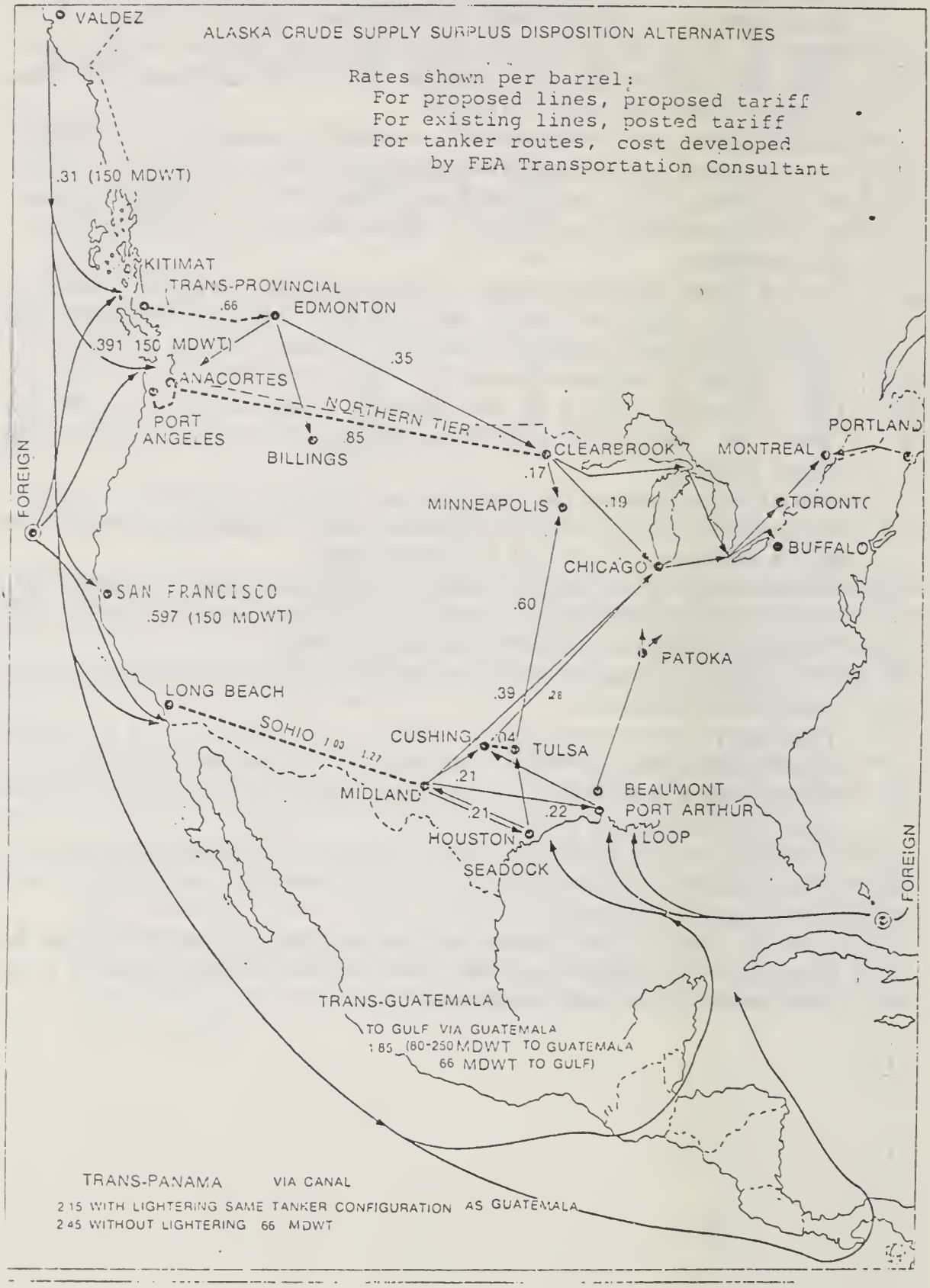
ALASKA CRUDE SUPPLY SURPLUS DISPOSITION ALTERNATIVES
Rates shown per barrel:
For proposed lines, proposed tariff
For existing lines, posted tariff
For tanker routes, cost developed by FEA Transportation Consultant
VALDEZ
.31 (150 MDWT)
KITIMAT
TRANS-PROVINCIAL
.66
EDMONTON
.391 150 MDWT)
.35
ANACORTES
NORTHERN TIER
PORT ANGELES
.85
BILLINGS
FOREIGN
CLEARBROOK
.17
MINNEAPOLIS
.19
MONTREAL
PORTLAND
TORONTO
BUFFALO
CHICAGO
SAN FRANCISCO
.597 (150 MDWT)
.60
PATOKA
LONG BEACH
.39
.28
SOHIO
1.03
1.27
CUSHING
.04
TULSA
.21
MIDLAND
BEAUMONT
PORT ARTHUR
.21
.22
HOUSTON
LOOP
SEADOCK
FOREIGN
TRANS-GUATEMALA
TO GULF VIA GUATEMALA
1.85 (80-250 MDWT TO GUATEMALA
66 MDWT TO GULF)
TRANS-PANAMA VIA CANAL
2.15 WITH LIGHTERING SAME TANKER CONFIGURATION AS GUATEMALA
2.45 WITHOUT LIGHTERING 66 MDWT

PARTS B AND C OF QUESTION IV ASKS THE FOLLOWING

If you have knowledge of these proposals, evaluate and compare the foregoing responses and any other relevant alternatives with respect to:

1. The current status of each project or proposal;
2. The estimated time for approval and implementation including description of:
   (*a*) any required Federal regulatory proceedings, approvals, leases or permits;
   (*b*) any required state regulatory proceedings, approvals, leases or permits;
   (*c*) any required regulatory proceedings, approvals, leases or permits which must be processed in other countries;
   (*d*) any treaty requirement; and
   (*e*) construction schedules, including if necessary, tanker construction schedules.
3. Direct capital and operating costs;
4. Financing arrangements;
5. Refiner and consumer costs of crude oil nationally and by region;
6. Wellhead price for North Slope crude oil, cash flow to the operating companies and revenues to the State of Alaska;
7. Net overall national economic costs and/or benefit;
8. Promotion of the capacity for long-term domestic self-sufficiency.
9. Environmental and safety impacts; and
10. Any other relevant factors.

C. IMPLEMENTATION

1. (a) Considering the foregoing factors, which of the alternatives or combination of them currently appears on balance to be best?
   (b) Which appear to be workable and acceptable?
   (c) Unworkable or unacceptable? (Why)?
2. (a) Among those alternatives identified as workable and acceptable which are now under active consideration by producers, refiners or others?
   (b) Which have reached the stage of applications for necessary certificates, licenses or permits?
3. For each of those alternatives identified as workable or acceptable what appear to be most significant critical hurdles to implementation (for example, demonstration of technical or economic feasibility; Federal or State air quality standards; obtaining competent and credible corporate sponsors; throughput commitment; legal authority; financing; Federal approval of required certificates, licenses or permits; foreign country, State or Provincial approvals or certificates, licenses or permits).
4. For each of those alternatives identified in IV A, what is your understanding of the time frame for completion? At what capacity?

There are two general problems which the final strategy ideally should overcome. First, the U.S. midwest shortfall, created by Canadian policy to shift increasing percentages of its available domestic oil to its eastern provinces (the Maritimes, Quebec and eastern Ontario) instead of to U.S. midwestern refineries and consumers; and

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second, the problem of surplus Alaskan crude arriving in California as a result of earlier route selection decisions to bring the Alaskan oil there.

Understandably, a number of respondents have particular interests in one or another of the proposed pipeline solutions, and their replies so indicate. The most useful responses were those of the FEA (which submitted a 460-page study in lieu of a response) and the ICC (which while readily admitting its limited scope and expertise, nevertheless submitted a balanced and useful response), and a partial reply from the FPC.

Not surprisingly, no single, outstanding, "obviously preferable" alternative emerges; each has potential advantages and drawbacks and each carries its own set of assumptions—long range and short range. Among these assumptions, two or three are accepted generally in the responses and are particularly noteworthy. First, the West Coast surplus will increase rather than decline over time. Second, the midwest (Chicago) region shortage will become more critical as Canada shuts off its export entirely in 1980 or 1981. Compounding this problem, northern tier refineries (except Chicago) are not well equipped to process north slope crude. Third, pipelines are seen as the only viable long-term mode for delivery of Alaskan crude.

Taking all of the responses together, some visible patterns develop. Briefly on the negative side, there was found:

—No support for the Guatemala pipeline. It is seen as much too vulnerable politically and from a defense posture, and, while potentially less expensive than tankers via the Canal or the Cape, not a long term viable economic alternative. Central American Pipeline Company claims it will build the line regardless.

—No support for shutting in crude in Alaska. It is seen as upsetting all the bases upon which financing and other calculations were made, and as a self-defeating move in the attempt to become more energy self-sufficient. All calculations appear to be bottomed upon a 30-year supply.

—No enthusiasm for attempting to develop economically viable desulphurizing (as a separate process plants at Valdez or elsewhere.

—No enthusiasm for substantially increasing the capacity of PADD V refineries to run or store high sulphur crude, and no visible evidence that such a move is under way.

More positively, the several agency and corporate responses revealed the following:

Transporting oil by tankers from Valdez to ports in the Gulf of Mexico for refining and/or forwarding through pipeline infrastructure already in place is seen as a short run, relatively expensive alternative. Tankers of up to about 65,000 DWT can transit the Panama Canal fully loaded. Larger ships (up to approximately 90,000 DWT) can transit the Canal partially loaded. Still larger tankers (over 90,000 DWT) would have to be routed via Cape Horn or transload oil into smaller tankers at the western entrance to the Canal. Use of existing U.S. (Navy) owned pipelines running parallel to the Canal is not seen as viable largely because of treaty agreements with Panama pre-

cluding our generating competition with waterborne trans-Canal traffic, and because it is relatively expensive. One respondent (Exxon) stated that it will be able to handle its oil surplus in its own tanker fleet. It sees the SOHIO or Midcontinent pipeline proposal as the best long term option, however. It seems far from certain that MARAD or Congress would be willing to relax cabotage laws enough to insure an adequate tanker fleet to handle this volume in total. However, all respondents assume that this will be done, one way or another.

While not one of the options included in the questionnaire, use of unit tank trains,[2] primarily to supply northern tier refineries, was offered as a consideration by the ICC and the FEA. Breakthroughs in loading-unloading technique make this a more promising alternative, although still quite expensive. Such trains already are in service elsewhere so the technique is not totally new.

While a direct response was not received from DOT, the FEA report notes that DOT recommends the use of VLCC's via the Northwest Passage, by-passing TAPS altogether, as being by far the least expensive method of delivering to refinery region I (northeast) which faces the most critical domestic crude shortage of all regions.

Purely from the standpoint of logistics and logistics expense, a three-way trade of crude between the U.S., Canada and Japan is seen by most respondents as the most sensible solution, especially in the short run. While very complex to the layman, the arrangements are considered by oilmen to be not unusual. Basically, what is proposed is that surplus Alaskan crude would be shipped to Japan to supplant part of its OPEC imports. Part or all of the OPEC oil thus supplanted would be shipped to, say, Portland, Maine for pipeline delivery to Canadian refineries in and near Montreal. This, in turn, would supplant Canadian oil produced in the province of Alberta and shipped east by pipeline from Edmonton to Sarnia and thence to Montreal. This, in turn, would replace Alberta crude which used to flow to U.S. northern tier states but which was diverted to eastern provinces as a result of Canada's self-sufficiency program precipitated by the Arab embargo and price moves. Presumably this plan, if properly executed, would work to everyone's advantage, economically. Whether or not it is sound as a policy matter is unclear, nor is it clear from respondents what Canada or Japan think of the idea. Legislation probably could be required in the U.S., since present law generally (though not absolutely forbids exporting Alaskan crude, at least to non-contiguous foreign countires.[3]

This leaves for reporting the responses bearing on the three proposed major pipeline projects; The Transprovincial (Canadian), the Northern Tier (Northwestern U.S.), and the SOHIO (also called the Midcontinent or the El Paso line). By far, the most useful and most comprehensive response on this was FEA's. As mentioned elsewhere, the study was not specifically tailored to the questionnaire but did become the formal FEA reply to it. Much of what follows is based on statements contained in that report.

Throughout the following summaries of the proposed pipeline projects, the reader should keep in mind that the Transprovincial and

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[2] See the appended GATX response for a further discussion of this.
[3] See the appended memo from the American Law Division.

the Northern Tier pipelines, by all current reckoning, are mutually exclusive. On the other hand, it is considered possible that the SOHIO line (Long Beach to Midland) could be economically viable in addition to one or the other (but, of course, not both) of the northern lines.

There is identified one other major pipeline proposal—the CAPICO [4] (Central American Pipeline Company) line, proposed to be constructed between Las Lisas and San Francisco del Mar, Guatemala. This ambitious project will be constructed to accommodate worldwide oil shipments, according to CAPICO, regardless of whether or not one or more of the other three lines are built. The developer claims the line will have an initial capacity of 800,000 B/pD and could reach 1.6 million B/pD. It proposes to use 250,000 DWT tankers from Valdez to Las Lisas and 65,000 DWT (average) tankers from San Francisco del Mar to U.S. Gulf and Atlantic ports. It claims it will be able to deliver crude from Valdez to New York, for example, for $1.82 per barrel.

Of the three proposed North American lines, it is argued that the Transprovincial line between Kitimat and Edmonton could be put on line the quickest, since there is reportedly less institutionalized opposition to its construction (environmental groups, provincial or community resistance, etc.) and could transport oil up to about 650,000 B/pD at a lower cost per barrel than either the Northern Tier or the SOHIO lines. Above 650,000 B/pD (its maximum under presently proposed configuration) the other two lines appear to have the cost edge.

It should also be remembered that at the present time so-called Northern Tier refineries (excluding Chicago) could be modified to refine only about 300,000 B/pD of high sulphur Alaskan crude. Thus, Transprovincial's start-up capacity would appear to satisfy that need.

Briefly, here are the physical and tariff rate particulars of each of the three North American line proposals as reported in the materials submitted for satisfying the questionnaire.

Transprovincial.—125,000 DWT tankers, Valdez to Kitimat (near Prince Rupert) B.C.; thence via new 800–mile, 30-inch pipeline to Edmonton, Alberta; thence via existing Canadian and U.S. (Interprovincial-Lakehead, Rangeland) pipelines to U.S. destinations, principally west of Chicago. Estimated ready time, including port construction work at Kitimat is 16 to 22 months (for up to 300,000 B/pD) after construction begins. Estimated transportation (tariff) rate, Valdez to *Edmonton*, Alberta is said to be 97 cents per barrel. Proposed maximum capacity is 650,000 B/pD. The twelve known consortium sponsors of this line are Amoco, Ashland, Continental, Husky, Murphy (all oil companies) Hudson Bay Oil and Gas, Farmers Union Central Exchange, Koch Industries, Marathon Pipeline Co., Interprovincial Pipe Line Ltd., Total Leonard Inc., and Trans-Mountain Oil Pipe Line Corporation.

There exists the possibility that one or more of the western (Canadian) Provinces might attempt to levy a transit tax on this oil. It is felt that this could be covered by treaty, however.

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[4] CAPICO requested an opportunity to respond, was sent a questionnaire, but failed to respond.

Northern tier.—150,000 DWT tankers from Valdez to Port Angeles, Washington, thence via a 36-inch pipeline, 1,500 miles across 5 western/midwestern states to Clearbrook, Minnesota, serving existing lines enroute, thence on to Chicago or other demand points via existing lines. Railroad rights-of-way will be used for about 400 miles of the line. Tanker unloading and oil storage facilities would have to be built at Port Angeles in addition to the 1,500-mile pipeline. Known participants in this consortium (officially called the Northern Tier Pipeline Co.) include Butler Associatees, Curran Oil Co., Glacier Park Co. (subsidiary of Burlington Northern), MAPCO, Inc., Milwuakee Land Co. (subsidiary of Milwaukee Road), Patrick J. McDonough, and Western Crude Oil. None has a major interest in any refineries to be served by Northern Tier nor do any of the members own any North Slope crude. The estimated cost of the line, including port work, is $1 billion. Initial capacity through to Clearbrook is said to be 400,000 to 600,000 B/pD, to be increased to 800,000 B/pD later. Cost to deliver each barrel of oil from Valdez to Clearbrook is claimed to be $1.24, including all port charges. Actual construction time is claimed to be 24 months *after* all clearances to proceed are finalized. This could take at least two additional years, barring protracted litigation. The line, of course, would be fully under U.S. control and not subject to Canadian federal or provincial taxes or regulations. The line is claimed to be designed to permit an additional 500,000 B/pD to be shipped to refineries in the Puget Sound area, in addition to the 400,000 to 800,000 B/pD to Clearbrook. Northern Tier claims it intends to finance this $1 billion project without resorting to throughput agreements—a highly unusual approach to pipeline financing and potentially quite expensive.

SOHIO.—150,000 DWT tankers from Valdez to Long Beach, California, thence a combination of new and existing pipelines (using the 800-mile El Paso natural gas pipeline already in place as the nucleus of the line) about 1,000 miles to Midland, Texas for further pipeline shipment to the east and midwest. Capital investment is estimated by SOHIO to be $500,000 and the cost of transporting oil from Valdez to Midland is said to be $1.55 per barrel. The line will accommodate 500,000 B/pD at full capacity and additional capacity could be built if needed. It is expected that work could be completed in 12 to 24 months, once clearances are received. The rub is that the California Air Resources Board (CARB) and the (federal) EPA have thus far stalled the project. SOHIO claims that the type of tanker it plans to operate will not create air pollution, but, so far, CARB and EPA are unconvinced. Another consideration is that in order to convert the existing El Paso gas pipeline for oil use, the FPC would have to allow abandonment of the line for natural gas. Once it was converted to crude, it would come under ICC jurisdiction, not FPC. The proposal seems to be on excellent financial footing, however.

Summing up the pros and cons of the three proposals, as derived from replies to the questionnaire, and the FEA draft report, the Transprovincial line appears the least likely to be bogged down in permit and licensing difficulties and promises the lowest rates to expected destinations for quantities up to its claimed 650,000 B/pD limit. It is a

foreign line, however, representing foreign investment and potentially exposed to the actions of a foreign government.

The Northern Tier line may have the potential for providing delivery to the largest number of demand points, represents a totally U.S. investment, is therefore not subject to foreign controls or taxation, and appears to offer lower rates at very high throughput levels. It may be quite vulnerable to governmental delays in start up at local, State and Federal levels, however, it requires high initial investment compared to the other two lines, and it appears that its proposed financing arrangements might be quite expensive. It would seem, also, that the lack of significant financial interest in either on-line refineries or in Alaskan crude output of its owners would be a disadvantage.

The SOHIO line would seem to have the advantage of being owned by a very healthy company which also owns the biggest share of TAPS crude. Aside from its current impasse with CARB/EPA, there do not appear to be other major regulatory delays to himper its construction, although FPC abandonment proceedings could be a possible snag. The most obvious drawback appears to be that it does little to help the Northern Tier crude shortage even though it does potentially help the region V (Chicago) shortfall, albeit via a rather circuitous route. However, while the two northern lines presently are considered to be mutually exclusive, the SOHIO line might well be built regardless of which of the two proposed northern lines is constructed (assuming one of them will be built).

PART D. FEDERAL POLICY ROLE

Questions

1. If none of the pipeline systems listed in IV and constructed in item to transport any of the anticipated West Coast surplus in PADD V created by North Slope crude oil production, how would you recommended the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV A 4–9.)

2. What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?

3. (a) Is there a need for Federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PADD V?

(b) What, if any, constraints should such legislation address?

Responses

To the extent that the responses were provided by questionnaire recipients, they generally have been summarized above.

There were very few specific suggestions for Federal legislation. Several responses mentioned the need to consider exchange agreements with noncontiguous nations, but legislation would not be necessary to meet that end if the President could make the appropriate findings as required by the statute.

No one respondent appeared to stress the need for Federal legislation to expedite the approval process for any one of the proposed pipeline

systems. The one possible exception was Sohio, which indicated it "may be necessary for Federal involvement to lend a national perspective", if states take actions which impede Sohio's progress. It is axiomatic that the State of California would disagree.

The ICC stressed the need to continue its jurisdiction over pipeline regulation if such regulation were expanded.

V. Costs and Prices

With the exception of the first one the thrust of the questions in this section is toward eliciting cost and price information on the several alternative measures proposed for relieving that portion of North Slope crude production which is excess to PADDY V. Question B looks to the anticipated tariffs for the pipeline segment of the transport system and for the tanker segment to the Trans-Provincial, Northern Tier, and SOHIO pipeline access points.

A. What is the full anticipated cost of constructing and equipping the Trans-Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction) ? To 1.6 and 2.0 million barrels per day?

Alyeska Pipeline responded that the current anticipated cost of constructing and equipping the Trans-Alaska Pipeline System and terminal facilities to transport 1.2 million barrels per day is $7.7 billion. This does not include interest costs, which are incurred by owners in financing conducted independent of Alyeska's construction activity. Exxon and SOHIO use the Alyeska estimate and add that currently capitalized interest expense is estimated at $1.3 billion, bringing the total cost to $9.0 billion. Such expenses are difficult to estimate in this case since during construction each participant carries its own interest costs, and the cost of money to each member varies, depending upon the extent of internally generated funds, credit ratings, and the timing and mix of debt and equity financing.

Expanson of the line to the 1.6 mmb/d level was recently estimated to cost an additional $675 million. Over a year ago, the cost to increase the line from 1.2 mmb/d to 2.0 mmb/d was estimated at $850 million. The Interstate Commerce Commission cites additional costs to attain a pumping capacity of 2.0 mmb/d at $750 million. It sees the total cost of the project to be $9.75 billion to $10.25 billion.

Because the allowed TAPS tariff will be based on a percentage of costs, the higher the pipeline costs the higher the tariff will tend to be. And from the State of Alaska's point of view, as the TAPS tariff increases the wellhead value and thus royalties to Alaska decrease. In this last connection the ICC reply noted that the attorney general of Alaska has already indicated that the State will probably protest initial TAPS tariff charges.

B. What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985. (Specify throughput assumptions.) What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to southern California?

In its reply the Federal Energy Administration points out that the eight companies owning the pipeline treat their percentage share as exclusive property and will separately publish tariffs and receive

tenders for shipment through their respective portions of TAPS' capacity. Further, since each member company is not required to participate in any expanded capacity (say from 1.2 million barrels per day to 2.0 million), ownership percentages could change after an expansion, thus requiring a recomputation of costs and presumably a different set of tariffs.

The FEA reply states that ICC limits each owner of an interstate pipeline to an annual 8 percent return on its "net replacement" costs under ICC valuation with the distribution of dividends limited to a 7 percent rate of return on the carrier's property. ARCO concludes that no definition tariff estimates are possible since ICC valuation guidelines for existing pipelines are largely inapplicable to TAPS and that final construction costs are of course not yet known. For its part, the ICC replied that it would be in appropriate for it to comment on possible tariffs since it must subsequently rule on the reasonableness of the tariffs proposed and should not prejudice those proceedings. It did, however, mention $4.50 per barrel for the pipeline tariff and 50 cents to $1.00 per barrel for the taker tariff as numbers which are talked about. The FEA study contains some tariff data cited from various industry analyses. These include a 1978 TAPS pipeline tariff of $4.60 per barrel for 1.2 million b/d throughput and tanker costs of 50 cents per barrel from Valdez to Los Angeles. (Another estimate was 46 cents Valdez to Los Angeles in 1981; 60 cents in 1987; and 75 cents in 1995). They also include transportation costs from Valdez to the Gulf Coast via the Panama Canal of $2.25 per barrel; to the Gulf Coast via tanker and pipeline of $1.65; and to Japan of $1.00.

Three industry responses to the tariff question were received. Alyeska Service Corporation will operate the pipeline as agent for the owners but will have no role in tariff determination or collection of charges. EXXON says it plans on a tariff of about $5.00 per barrel in the early years of operation and about $4.00 per barrel in the 1985 time frame. SOHIO also sees the pipeline tariff as $4.00–$5.00 per barrel, assuming a $7.7 billion total construction cost, a 7 percent return, and a 1.2 million b/d throughput.

With respect to tanker tariffs, EXXON expects rates from 1980–1985 (on a new 190 MDWT new vessel of today's costs) for shipments from Valdez to the average West Coast port to be about $1.00 to $1.15 per barrel. SOHIO estimated tanker costs from Valdez to Kitimat at 35 cents to 50 cents per barrel; to Puget Sound at 40 cents to 55 cents per barrel; and to Southern California at 60 cents to 80 cents per barrel.

C. To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act, or (b) at the upper tier price established by the FEA, be expected to constrain West Coast refinery prices? Refinery prices East of the Rockies?

EXXON, in citing a series of "unresolved factors" that bear on the answer to this question, concluded that "speculation on future price under conditions of each uncertainty would not be fruitful." SOHIO replied that a wellhead ceiling price established at either the composite domestic average price or at the upper tier price would constrain the market price of Alaskan oil, if that ceiling price, *plus* the

TAPS tariff, *plus* the marine cost and other transportation cost, is less than the price for foreign crude in the market when the Alaskan crude oil is to be sold. Using today's ceiling prices, foreign oil prices and cost estimates, SOHIO concluded that neither price level would be a constraint on Alaskan oil, but that this could change in the future.

ARCO responded in some detail stating that the landed cost of alternative (foreign) crude oil would determine the landed value of North Slope crude and that while it was not possible to definitely predict the transportation tariffs, current comparable costs for foreign crude oil would constrain Prudhoe Bay crude prices to less than the current upper tier prices. Consequently, competition would constrain product prices. ARCO felt, therefore, that imposition of ceiling prices on North Slope crude would not be necessary or desirable. ARCO expects that situation to continue for the foreseeable future.

Because of the uncertainty of transportation expenses from the North Slope, ARCO said it is not possible to assess the effect a limitation to the composite price of the EPCA would have on product prices. However, current regulations would not impose such a limit, and if that limit were less than the competitive value of North Slope crude, ARCO believes its imposition would be grossly inequitable.

With respect to the effect price limits on North Slope crude would have on East Coast product prices, ARCO stated it is axiomatic that the greater expense of transporting North Slope crude to the East Coast, and the relatively less expensive cost of transporting foreign crude to those ports, would result in downward competitive pressure on North Slope wellhead prices.

The FEA study points out that the Emergency Petroleum Allocation Act of 1973 as amended expects the Alaskan crude oil production to be factored (as new or upper tier oil) into the calculation of the composite price and the concomitant lower and upper tier ceiling prices, as soon as such production commences. However, the Act allows, after appropriate findings and determinations by FEA, the exemption of a specified amount of Alaskan crude oil production from this calculation. FEA says the question of the level of future prices for Alaskan crude is unresolved at this time and that a reasonable statement is that, if, for example, Alaskan crude is priced as upper tier oil, the upper tire price ceiling will apply to the wellhead price. The controlling effect of the crude oil market in various areas of the lower 48 states combined with a TAPS tariff in the range of $4.00 could keep the wellhead price of North Slope crude below this ceiling.

FEA remarks that in any event the Energy Policy and Conservation Act merely provides for the exclusion of Alaskan crude oil from the composite weighted average price. It offers no further guidance for pricing policy or implementation. FEA has just begun to consider now the policy questions surrounding this issue. It reports that a study of this issue has been commissioned by the Office of Regulatory Programs, to be completed by April of 1977, as required by Congress.

D. If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g., imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?

ARCO in reply to this question stated simply that it did not expect the establishment of multiple wellhead prices for North Slope crude. On the other hand, SOHIO responded that for oil which is not used on the West Coast but is transported to other U.S. markets, the wellhead realization for that oil would be reduced to the extent that the additional transportation costs would have to be absorbed by the seller. In this case, there would be more than one wellhead realization for North Slope crude. SOHIO did point out that it expects the largest portion of Alaskan oil to be used on the West Coast and, assuming free market conditions, the wellhead realization for oil so used will be approximately the landed cost of foreign sour crude oil on the West Coast, less the marine cost from Valdez to the discharge port and less than TAPS pipeline tariff.

E. To what extent, if at all, would the alternative measures identified in Question IV–A affect average prices of North Slope and similar grade crude oil produced in PADD V (a) at the wellhead, (b) at West Coast refineries, and (c) at refineries east of the Rockies?

ARCO replied that there are too many major unknowns to be able to quantify the extent to which any of the alternatives in Q. IV–B would affect West Coast wellhead prices. The company did state that assuming a free market, West Coast crude will compete with alternative source crude on a landed cost basis and that as the capital costs of those respective alternatives increase, the transportation costs would increase with a corresponding downward pressure on the wellhead prices of West Coast crude.

SOHIO responded by saying that if the alternative(s) used to relieve the surplus of crude oil on the West Coast is effective, there should be no impact at West Coast refineries or at refineries East of the Rockies since foreign crude would be replaced at essentially the same cost to the refiner.

In the event that an alternative is used that is not capable of relieving the surplus, and no additional means are instituted, SOHIO felt the situation could arise where a glut of Alaskan quality oil on the West Coast could drive prices down for that oil (and comparable quality domestic California production) on the West Coast while other areas of the country remain crude deficient and reliant on foreign imports for a considerable part of their supply.

The FEA study contains an illustration of potential crude oil acquisition costs for three markets (p. 454) assuming that all refiners would buy North Slope crude when sold for 25 cents/barrel *less* than the landed price of Arabian light crude. Under this assumption FEA sees Japanese refiners willing to pay $11.43/bbl for North Slope crude, Gulf Coast refiners $12.39/bbl, and West Coast refiners $12.19/bbl. These several figures depend of course on the relations of the F.O.B. Valdez price to Persian Gulf prices plus the relative transport costs and any import fees.

ADDENDUM

THE LIBRARY OF CONGRESS,
CONGRESSIONAL RESEARCH SERVICE,
Washington, D.C., November 23, 1976.

To: Senate Interior and Insular Affairs, Attn.: Betsy Moler.
From: American Law Division.
Subject: Alaskan pipeline rights-of-way and oil exports.

The annexed reports are submitted in response to your inquiry of November 10, 1975, raising the following questions:

1. What vehicle or form is necessary to bring export provisions into operation?
2. Would shipments to Mexico and Canada be considered "exports"?
3. Would any swapping arrangements be under the controlled price" or world market price? What price basis is set up under the law?

For reasons expressed in these reports, a presidential message finding exports, *inter alia*, in the national interest together with the absence of a concurrent resolution disapproving same would "trigger" the export waiver; that shipments outside the U.S. are exports; that exchanges authorized under the Mineral Leasing Act of 1920, as amended, 30 U.S.C. 185 (u) (Supp.) would be at world market prices.

RAYMOND CELADA,
Senior Specialist in American Public Law.

ALASKAN PIPELINE RIGHTS-OF-WAY AND OIL EXPORTS

(By Raymond Celada, Senior Specialist in American Public Law, November 23, 1976)

1. What vehicle or form is necessary to bring the export provisions into operation?

Section 28(u) of the Mineral Leasing Act of 1920 (41 Stat. 449), as amended (30 U.S.C. 185) provides as follows:

> Any domestically produced crude oil transported by pipeline over rights-of-way granted pursuant to this section, except such crudes in similar quantity for convenience or increased efficiency of transportation with persons or the government of an adjacent foreign state, or which is temporarily exported for convenience or increased efficiency or transportation across parts of an adjacent foreign state and reenters the United States, shall be subject to all of the limitations and licensing requirements of the Export Administration Act of 1969 and, in addition, before any crude-oil subject to this section may be exported under the limitations and licensing requirements and penalty and enforcement provisions of the Export Administration Act of 1969 the President must make and publish an express finding that such exports will not diminish the total quantity or quality of petroleum available to the United States, and are in the national interest and are in accord with the provisions of the Export Administration Act of 1969. Provided, That the President shall submit reports to the Congress containing findings made under this section, and after the date of receipt of such report Congress shall have a period of sixty calendar days, thirty days of which Congress must have been in session, to consider whether exports under the terms of this section are in the national interest. If the Congress within this time period passes a concurrent resolution of disapproval stating

disagreement with the President's findings concerning the national interest, further exports made pursuant to the aforementioned Presidential findings shall cease.

The limitation on exports provided for in section 28(u), P.L. 93–153, 85 Stat. 576, 582(1973) was intended to allay fears that oil from the North Slope at Prudhoe Bay, for various economic reasons, would be shipped abroad. The immediate need for the legislation of which section 28(u) was a part was two-fold: first, to overcome the decision of the United States Court of Appeals for the District of Columbia Circuit in *Wilderness Soc.* v. *Morton*, 479 F. 2d 842 (D.C. Cir. 1973), *cert. denied* 411 U.S. 917 (1973), which held that the Interior Secretary's authority to grant rights-of-way in federal lands was confined to widths specified in then existing law—widths deemed insufficient to develop the North Slope reserve irrespective of the route ultimately selected for moving the petroleum from the Prudhoe Bay area; second, to authorize the Trans-Alaska Pipeline (TAP) which would carry the crude thus produced to Port Valdez for conveyance by tanker to the U.S. west coast. S. 1081 and H.R. 9130, 93rd Congress, were designed to accomplish both these purposes.

The legislation divided both Senate and House Chambers between those who wanted to develop in the fastest manner possible the North Slope resource in order to head-off an emerging oil-energy crisis and those, largely from the Mid-west and East, who felt that their energy-short constituencies would literally be left out in the cold by TAP development and various intervening supply and economic developments. Accordingly, the former sided with TAP while the latter pushed for a Trans-Canada Pipeline (TCP) which would bring oil from Prudhoe Bay closer to their home areas. One of the arguments made by opponents of TAP was that it would eventually lead to a glut of oil on the west coast which together with cost and other factors would induce North Slope developers to sell oil abroad, particularly to Japan. See Senate Report No. 93–207, pp. 25–28.

TAP supporters who emphasized the need for immediate domestic energy sources generally prevailed. Thus in congressional findings,

The Congress finds and declares that: (a) The early development and delivery of oil and gas from Alaska's North Slope to domestic markets is in the national interest because of growing domestic shortages and increasing dependence upon insecure foreign sources. Sec. 202.

The bill that became law made a number of concessions to opponents. Title III, for example, authorized the President to enter negotiations with Canada with a view to the latter's receptivity toward "construction of pipelines or other transportation systems across Canadian territory for the transport of natural gas and oil from Alaska's North Slope to markets in the United States." Sec. 301(a).

Additionally, the Secretary of the Interior was authorized "to investigate the feasibility of one or more oil or gas, pipelines from the North Slope of Alaska to connect with a pipeline through Canada that will deliver oil or gas to United States markets." Sec. 302.

Further, section 410 calls for "Equitable Allocation of North Slope Crude Oil" as follows:

The Congress declares that the crude oil resources and that benefits of such crude oil should be equitably shared, directly or indirectly, by all regions of

the country. The President shall use any authority he may have to insure an equitable allocation of available North Slope and other crude oil resources and petroleum products among all regions and all of the several States.

Section 28(u) was intended to express "concern that the companies that control North Slope oil reserves might decide, on the basis of private commercial advantage, to make export sales or exchanges that result in a net reduction of crude oil supplies available to the United States, or an increased dependence of the United States upon insecure foreign supplies." Senate Report No. 93–207, at 27.

Briefly, section 28(u) was intended to provide a statutory check upon exports on oil produced on Alaska's North Slope.

It will be observed that that section is not a categorical prohibition of oil exports. An all-out ban was dismissed as being unwise.

There might well be a situation in which export-for import arrangements would be of benefit to both the United States and its trading partners. For example, the export to Japan of Alaskan crude oil supplies to west coast needs in exchange for Latin American or Eastern Hemisphere crude (which would otherwise have been transported to Japan) for the Northeast could, under some circumstances, be a better arrangement to bringing the Northeast region additional crude oil supplies than either transcontinental pipelines or a tanker route around the Horn. A total prohibition might, in addition, encourage other countries to restrict exports to the United States, or cripple efforts to provide cooperation or sharing of restricted supplies among consuming countries. Senate Report No. 93–207, at 28.

At the insistence of the House, section 28(u) is not limited to the Trans-Alaskan Pipeline; "it applies to all pipelines on rights-of-way granted under section 28 of the Mineral Leasing Act of 1920, either before or after the amendment of that section by" P.L. 93–153. House Report No. 93–414, p. 18. See also Conference Report, House Report No. 93–617, p. 24: "The House amendment applied to oil transported over rights-of-way through Federal lands. The Conferees adopted the House language."

Although section 28(u) does not flatly prohibit the export of North Slope crude oil (or any U.S. domestically produced oil that, at some point, is carried in pipelines over Federal rights-of-way), it establishes certain mandatory legal requirements which effectively limit such exports to two specified circumstances. The first exceptional circumstance involves an equal exchange of temporary export of crude oil with an adjacent country. Thus, in the case of Canada, for example, the limitation on exports mandated by that section does not apply to oil (1) which is exchanged for a similar quantity as a convenience or to increase efficiency or transportation or (2) which is temporarily exported for convenience or increased efficiency of transportations.

The second exceptional circumstance arises when the President finds that the export of oil "will not diminish the total quantity or quality of petroleum available to the United States and are in the national interest and are in accord with the Export Administration Act of 1967." The Export Administration Act lapses on September 30, 1976, 50 U.S.C. 2413 (Supp.), but President Ford, in an Executive Order dated October 1, 1976, has directed the Commerce Department to continue administering the export control program under the emergency provisions of the Trading With the Enemy Act of 1917, as amended, 50 U.S.C. App. 5. E.O. 11940, 41 E.R. 43707 (Sept. 30, 1976).

That Act, empowers the President to "prohibit or curtail exports of any articles, materials or supplies, including petroleum, when it becomes necessary to protect the domestic economy from excessive drain of scarce materials and to reduce the serious inflationary impact of foreign demand." 50 U.S.C. 2402(a) (Supp.)

Under terms of section 28(u), the President "must" not only "make" the requisite finding, but "publish" it as well. Additionally, the President is required to report his findings to the Congress which has sixty days to "consider whether exports under the terms of this section are in the national interest." During the specified period, Congress may disapprove of the President's report by concurrent resolution . . . Thereafter, "further exports made pursuant to the aforementioned Presidential findings shall cease."

Neither the express wording of section 28(u) nor the legislative history of P.L. 93–153 provide a clue as to the nature of the report which would permit otherwise prohibited exports of domestically produced oil that at some point, is carried in pipelines over federal rights-of-way. Although the form of the required report is thus left to executive discretion, the practice suggests that a presidential message would suffice. "The message of the Presidents include every communication to Congress, whether made in person or transmitted in writing." Schmeckbier, *Government Publications and Their Use* 308 (C) 1961. The context of section 28(u) indicates that a written report was intended. A similar reporting requirement in the War Powers Resolution, 50 U.S.C. 1543(Supp.), has been complied with by such a message. See, for example, 11 Weekly Comp. of Pres. Docs. 514–515 (May 19, 1975).

2. Would shipments to Mexico and Canada be considered to be "exports"?

We have found nothing in P.L. 93–153, its legislative history, or other provisions of law suggesting a different conclusion.

> . . . the word "export" as used in the Constitution and laws of the United States, generally means the transportation of goods from this to a foreign country. "As the legal notion of emigrating is a going abroad with an intention of not returning, so that of exportation is a severance of goods from the mass of things belonging to this country with an intention of uniting them to the mass of things belonging to some foreign country or other." 17 Op. Attys. Gen. 583 *Swan & Finch Co.* v. *United States*, 190 U.S. 143, 145 (1903). To export means to carry or send abroad; to import means to bring into the country. Those acts begin and end at water's edge. *Canton R. Co.* v. *Rogan*, 340 U.S. 511, 515 (1951).

A further indication that crude oil shipments to these two countries are to be considered exports is found in section 103 of the Energy Policy and Conservation Act, P.L. 94–163, December 22, 1975, as amended by P.L. 94–385, August 14, 1976. That section authorizes the President to restrict and prohibit exports of specified energy sources when he deems it appropriate. In utilizing this authority, the President is directed to "take into account . . . the historical trading relations of the United States with Canada and Mexico." Clearly, if shipments of covered materials to these two countries were not "exports", there would be little need for the described caveat.

3. Would any swapping arrangements be under the "controlled price" or world market price? What price basis is set up under the law?

Although section 28(u) of P.L. 93–153 was the subject of substantial interest and discussion, the matter of which price applied to permitted exchanges, controlled or world market, seems to have been overlooked. The wording of the exchange provision, however, provides that permitted exchanges are to be "in similar quantity." If the requirement set out in that prepositional phrase is to be complied with, exchanges would have to be at world market price. It should be noted that under current regulations, exports are exempt from oil price requirements.

1. Federal Energy Guidelines 13,517.

RAYMOND CELADA,
Senior Specialist in American Public Law,
American Law Division.

APPENDIX

Responses to Questionnaire

79-745 O - 76 - 4

APPENDIX

The questionnaire was sent on August 23, 1976 to 13 Federal agencies and departments; to the Governors of Alaska, California, and Washington; and to 6 private companies. Copies of the questionnaire were sent at later dates to 4 more private companies. This Study includes replies received as of November 1, 1976.

The recipients were:

Federal Government—
- Department of Commerce.
- Department of Defense.
- Department of the Interior.
- Department of State.[1]
- Department of Transportation.
- Environmental Protection Agency.
- Federal Energy Administration.
- Federal Power Commission.
- Interstate Commerce Commission.
- Maritime Administration.
- U.S. Army Corps of Engineers.

States—
- Alaska.
- California.
- Washington.

Private companies/individuals—
- Alyeska Pipeline Service Co.
- Atlantic Richfield.
- Central American Pipeline Co.
- Exxon.
- General American Transportation Corp.
- K. M. Associates.
- Kitimat Pipeline Co.
- Northern Tier Pipeline Co.
- Portal Pipe Line Co.
- Standard Oil Co. (Ohio).

The Department of the Interior and the Federal Energy Administration submitted responses to parts I, II, and III. The Federal Power Commission responded to parts I–IV based upon information submitted by Sohio for the record in an abandonment proceeding before the Commission. The Interstate Commerce Commission responded in part to parts IV and V. No other substantive responses were received from the Executive branch.

The Federal Energy Administration submitted a draft of its study for the Energy Resources Council, "North Slope Crude: Where to? How?" in response to a request made at a September 21 hearing on the

[1] Did not reply to questionnaire.

issue held jointly by the Senate Committee on Interior and Insular Affairs and the Senate Commerce Committee. Because FEA did not complete its response to the questionnaire in time to be analyzed for this Study, the information contained in the draft report was used in lieu of a formal FEA response. The FEA was informed by staff of its intention to use this approach. Analysts were aware of the possible pitfalls in using this approach, but it seemed even less desirable to omit the information made available by the FEA entirely. Many of those agencies which did not respond to the questionnaire deferred instead to the FEA study in the belief that it would be the definitive study on the issue available from the Executive branch.

Responses from the Governors of Alaska and Washington have been included. The Governor of California asked the Chairman of the California Energy Resources Conservation and Development Commission to respond on his behalf. That response has also been included.

The responses from Alyeska, Atlantic Richfield, Exxon, Kitimat, Northern Tier, and Sohio have been included in the analysis. Central American Pipeline Company did not reply. General American Transportation Corporation, K. M. Associates, and Portal Pipe Line Company chose not to reply to the specific questions asked but did respond for the record. Their replies have been reproduced in this Appendix but have not been included in the analytical portions of the Study.

A copy of the letter accompanying the questionnaire which was signed by Senators Jackson, Magnuson, and Stevenson follows, along with a copy of the questionnaire, and the replies.

U.S. SENATE,
Washington, D.C., August 23, 1976.

Hon. FRANK G. ZARB,
Administrator, Federal Energy Administration,
Washington, D.C.

DEAR MR. ADMINISTRATOR: As you know, the trans-Alaska pipeline system is scheduled for completion in 1977. Alyeska Pipeline Service Company hopes to begin transportation of 600,000 barrels per day of North Slope crude oil from Prudhoe Bay to Valdez in June, 1977 and then increase throughput to 1.2 million barrels per day in November, 1977. While there may be some question whether that precise schedule will be met, there is no question that at some point in the near future there will be a substantial amount of North Slope crude oil available for shipment to the West Coast or elsewhere under the terms and conditions of the Trans-Alaska Pipeline Authorization Act.

The Senate Committees on Interior and Insular Affairs and Commerce have been concerned for some time now about the effect this crude oil will have on the overall West Coast supply and transportation system and whether adequate planning and preparation have been undertaken in order to fully accommodate this new domestic source of supply. The general supply situation in Petroleum Administration for Defense District V (PADD V) will also be affected by recently authorized production from the Elk Hills Naval Petroleum Reserve and expected production resulting from the Outer Continental Shelf leas-

ing program. There are a number of very critical issues associated with completion of the trans-Alaska pipeline that merit careful attention. These include:

—The timing for and anticipated levels of North Slope oil production;

—The capability of West Coast refineries to process Alaska crude oil;

—The plans, if any, of the producing companies to export or exchange Alaska crude oil and the policy of the Administration toward oil export or exchange agreements with Japan or other nations;

—Whether Alaska crude oil which is surplus to West Coast needs, or not capable of being refined on the West Coast, will be transshipped to other areas of the United States;

—The need, if any, for new legislative authority to deal with potential problems associated with the delivery of crude oil from Alaska's North Slope; and

—Whether the appropriate units of the Federal government are fully and properly exercising their responsibility for resolving these issues in a manner which serves the national interest.

In exercise of our oversight responsibilities and to undertake a structured examination of these issues, the enclosed questionnaire has been prepared. We would appreciate it if you would respond to all of the questions.

We request that you return the completed questionnaire by no later than September 13, 1976. Any questions you or your staff may have in answering the questionnaire should be directed to Betsy Moler of the Interior Committee's professional staff at (202)224–0611 or Steve Flajser of the Commerce Committee's professional staff at (202)224–8146.

We appreciate your cooperation in this effort.

With best wishes,

Sincerely,

WARREN G. MAGNUSON, U.S.S.
HENRY M. JACKSON, U.S.S.
ADLAI E. STEVENSON, U.S.S.

Enclosure.

QUESTIONNAIRE—POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

I. West Coast Petroleum Supply

A. CRUDE OIL

1. Alaska

(a) What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska pipeline?

(b) To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

(c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in

the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

2. West Coast Production

(a) What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PADD V)?

(b) What are your best current projections of production of crude oil in PADD V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

3. Imports

(a) What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulphur content).

(b) What are your best current projections of crude oil and product imports into PADD V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in question IV A).

B. REFINERY CAPACITY

1. What is the current refinery capacity and throughput in PADD V?

2. What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

3. What part of the current and projected PADD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

II. West Coast Petroleum Demand

A. What is the current demand for crude oil and refined petroleum products in PADD V?

B. What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

III. West Coast Surplus

Assuming that none of the measures identified in question IV A is implemented:

A. What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V (i.e., the difference between total PADD V production and refinery runs plus addition to stocks)?

B. What are your best current estimates of the PADD V surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PADD V production and refinery runs plus additions to socks of such crude oil)?

IV. Proposed Responses to the Projected West Coast Surplus

A. Proposed responses to deal with the projected surplus of North Slope grades of crude oil on the West Coast have included one or a combination of the following:

1. Construction of the proposed Trans-Provincial pipeline from Kitimat, British Columbia connecting with the Inter-Provincial pipeline at Edmonton;

2. Construction of the proposed Northern Tier pipeline from Port Angeles, Washington to Clearbrook, Minnesota;

3. The proposed Sohio project to convert and reverse an existing El Paso Natural Gas pipeline and build necessary connecting pipelines from Long Beach, California to Midland, Texas;

4. Construction of a pipeline across the Isthmus of Panama or across Guatemala to connect tanker routes from Alaska with tanker routes to the U.S. Gulf Coast;

5. Use of small tankers through the Panama Canal or VLCCs around Cape Horn to the U.S. Gulf Coast;

6. Retrofitting existing District V and/or Northern Tier refineries to run North Slope or comparable grades of crude oil:

7. Construction of one or more facilities (at Valdez, Kitimat, Port Angeles or elsewhere) to desulphurize and raise the gravity of North Slope Crude oil, in order to use it in existing West Coast and/or Northern Tier refineries;

8. Shutting in of producing capacity in the field and/or postponement of the increases in pipeline capacity on a short-term basis (pending increases in PADD V crude oil demand to absorb the surplus); and

9. Exports or exchanges with Canada, Japan or other countries either on a short-term basis (pending implementation of one or more of the foregoing systems) or on a long-term basis (pending increases in PADD V crude oil demand to absorb the surplus).

B. If you have knowledge of these proposals, evaluate and compare the foregoing responses and any other relevant alternatives with respect to:

1. The current status of each project or proposal;

2. The estimated time for approval and implementation including a description of: (a) any required federal regulatory proceedings, approvals, leases or permits; (b) any required state regulatory proceedings, approvals, leases or permits; (c) any required regulatory proceedings, approvals. leases or permits which must be processed in other countries; (d) any treaty requirements; and (e) construction schedules, including if necessary, tanker construction schedules.

3. Direct capital and operating costs;

4. Financing arrangements;

5. Refiner and consumer costs of crude oil nationally and by region:

6. Wellhead price for North Slope crude oil, cash flow to the operating companies and revenues to the State of Alaska;

7. Net overall national economic costs and/or benefit;

8. Promotion of the capacity for long-term domestic self-sufficiency;

9. Environmental and safety impacts; and

10. Any other relevant factors.

C. IMPLEMENTATION

1. (a) Considering the foregoing factors which of the alternatives or combination of them currently appears on balance to be best? (b) Which appear to be workable and acceptable? (c) Unworkable or unacceptable? (Why)?

2. (a) Among those alternatives identified as workable and acceptable which are now under active consideration by producers, refiners or others? (b) Which have reached the stage of applications for necessary certificates, licenses or permits?

3. For each of those alternatives identified as workable or acceptable what appear to be most significant critical hurdles to implementation (for example, demonstration of technical or economic feasibility; Federal or State air quality standards; obtaining competent and credible corporate sponsors; throughout commitment; legal authority; financing; Federal approval of required certificates, licenses or permits; foreign country, State or Provincial approvals or certificates, licenses or permits).

4. For each of those alternatives identified in IV A, what is your understanding of the time frame for completion? At what capacity?

D. FEDERAL POLICY ROLE

1. If none of the pipeline systems listed in IV A 1–3 (Kitimat, Northern Tier, and Sohio) is approved and constructed in time to transport any of the anticipated West Coast surplus in PADD V created by North Slope crude oil production, how would you recommend the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV A 4–9).

2. What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?

3. (a) Is there a need for Federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PADD V? (b) What, if any, constraints should such legislation address?

V. Costs and Prices

A. What is the full anticipated cost of constructing and equipping the Trans-Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?

B. What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985. (Specify throughput assumptions)? What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?

C. To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act, or (b) at the upper tier price established by FEA, be expected to constrain West Coast refinery prices? Refinery prices East of the Rockies?

D. If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g. imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?

E. To what extent, if at all, would the alternative measures identified in question IV A affect average prices of North Slope and similar grade crude oil produced in PADD V (a) at the wellhead, (b) at West Coast refineries, and (c) at refineries East of the Rockies?

UNITED STATES DEPARTMENT OF COMMERCE
Office of the Secretary
Washington, D.C. 20230

August 24, 1976

Honorable Henry Jackson
United States Senate
Washington, D. C. 20510

Dear Senator Jackson:

Secretary Richardson has asked me to acknowledge your letter dated August 23, which was also signed by Senators Magnuson and Stevenson, requesting information on the progress of the trans-Alaska pipeline system.

You may be assured that this matter will receive our closest consideration and that a further response will be forthcoming as soon as possible.

Sincerely,

Mansfield D. Sprague
Counsellor to the Secretary
for Congressional Affairs

THE SECRETARY OF COMMERCE
Washington, D.C. 20230

SEP 28 1976

SEP 27 1976

Honorable Henry M. Jackson
Chairman
Committee on Interior and Insular Affairs
U.S. Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Thank you for your letter of August 23 with regard to the effects that Alaskan crude oil will have on the overall West Coast oil supply and transportation systems.

You will by now have received from the Department of Interior and the Federal Energy Administration responses to three of the five major question areas which you posed. Responses to the fourth and fifth question areas must await completion of our Energy Resources Council's study.

We quite agree that the supply situation in PADD V poses a number of critical questions beginning in mid-1977. It is our hope, through the ERC study effort, to develop the kind of analysis upon which rational choices can be made as to the means by which Alaskan crude oil can be absorbed in meeting U.S. energy requirements.

We will, of course, welcome your views and those of your staff in the process.

Kindest regards,

Sincerely,

Elliot L. Richardson

UNITED STATES DEPARTMENT OF COMMERCE
Office of the Secretary
Washington, D.C. 20230

September 15, 1976

Honorable Henry M. Jackson
Chairman
Committee on Interior and Insular Affairs
United States Senate
Washington, D. C. 20510

SEP 17 1976

Dear Mr. Chairman:

Thank you for your letter of September 9 to Secretary Richardson inviting him to testify before the Senate Committee on Commerce and Committee on Interior and Insular Affairs' joint oversight hearing September 21 concerning the delivery of crude oil from Alaska's North Slope and its impact on the West Coast crude oil supply situation.

An extensive study of this subject is now under way under the auspices of the Federal Energy Administration. The study is not expected to be completed until late this month, and a comprehensive policy analysis of the study and its conclusions is not expected before late October. As a consequence, Secretary Richardson does not believe he would be able to offer the joint committee any new data on this subject at this particular time.

I understand that Mr. Frank Zarb, Administrator of the Federal Energy Administration, is scheduled to testify before the joint hearing. Secretary Richardson believes that Mr. Zarb will be able to discuss the West Coast crude oil supply study and answer any questions that you and your colleagues may have.

I have also written Senators Magnuson and Stevenson similar letters as they co-signed the September 9 correspondence to the Secretary.

Sincerely,

Mansfield D. Sprague

Mansfield D. Sprague
Counsellor to the Secretary
for Congressional Affairs

ASSISTANT SECRETARY OF DEFENSE
WASHINGTON, D.C. 20301

SEP 16 1975

INSTALLATIONS AND LOGISTICS

14 SEP 1976

The Honorable Henry M. Jackson
Chairman, Committee on Interior
and Insular Affairs
United States Senate
Washington, D. C.

Dear Senator Jackson:

This is in response to your letter of 23 August 1976 to Secretary Rumsfeld concerning the start of delivery of Alaskan North Slope crude oil to the West Coast about June 1977, and the effect this crude oil will have on the overall West Coast supply and transportation system. You also indicated concern over whether adequate planning and preparation have been undertaken in order to fully accommodate this new domestic source of supply.

In order to gather desired information for use in performance of committee oversight responsibilities on these issues, a questionnaire was developed. Your letter of 23 August asked the Department of Defense to respond to Question IV of the Questionnaire, plus any additional questions on which DoD might have information of use to the Committees. Question IV lists nine proposed responses for dealing with the projected West Coast surplus, including delivery systems, refinery retrofit, reduced crude oil deliveries and exchange agreements for or exports of Alaskan crude oil.

The method by which delivery of the crude oil is accomplished to refineries within the United States is a subject considered to be outside the cognizance of the Department of Defense. Accordingly, the Department of Defense defers to other interested Federal Executive Agencies with respect to the Committee questionnaire.

The Office of Management and Budget advises that from the standpoint of the Administration's program, there is no objection to the presentation of these views for the consideration of the Committee.

Sincerely,

FRANK A SHRONTZ
Assistant Secretary of Defense
(Installations and Logistics)

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

SEP 14 1976

In Reply Refer To:
EM-ES-19474 & 20142

SEP 15 1976

Dear Mr. Chairman:

In response to your letter of August 23, 1976, attached are the answers to those questions for which the Department of the Interior has information readily available.

The answer to the remainder of the questions will be provided by other agencies when the necessary information is available.

I also have your letter of September 9, 1976, inviting me to appear before a joint oversight hearing on the same general subject by the Senate Committees on Interior and Insular Affairs and Commerce on September 21, 1976. Although I am committed to being out of the city on that day, I have asked Assistant Secretary--Energy and Minerals William L. Fisher to appear for me at the hearing.

Sincerely yours,

Secretary of the Interior

Hon. Henry M. Jackson
Chairman, Committee on Interior
and Insular Affairs
United States Senate
Washington, D. C. 20510

Enclosure

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

In Reply Refer To:
EM-ES-19474 & 20142

SEP 14 1976

Dear Mr. Chairman:

In response to your letter of August 23, 1976, attached are the answers to those questions for which the Department of the Interior has information readily available.

The answer to the remainder of the questions will be provided by other agencies when the necessary information is available.

I also have your letter of September 9, 1976, inviting me to appear before a joint oversight hearing on the same general subject by the Senate Committees on Interior and Insular Affairs and Commerce on September 21, 1976. Although I am committed to being out of the city on that day, I have asked Assistant Secretary--Energy and Minerals William L. Fisher to appear for me at the hearing.

Sincerely yours,

(Sgd) Tom

Secretary of the Interior

Hon. Henry M. Jackson
Chairman, Committee on Interior
and Insular Affairs
United States Senate
Washington, D. C. 20510

Enclosure

RESPONSES TO SELECTED QUESTIONS CONTAINED IN JACKSON, MAGNUSON, STEVENSON LETTER OF AUGUST 23, 1976

I. West Coast Petroleum Supply

A. Crude Oil

1. Alaska

a) Q. What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska pipeline?

A. The present estimate of completion on the Trans Alaska Pipeline System, projected by the Owners of the System, is that first thru-put will occur in the third quarter of calendar 1977.

b) Q. To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

A. Alyeska Pipeline Service Company, the agent of the Owners of the Trans Alaska Pipeline System, indicates to us that the above date reflects the resolution of pipeline welding problems and any other anticipated technical delays.

c) Q. What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

A. The best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel) are:

1977	1978	1980 through 1985	
600 tbd	1.2 mmbd	1.6mmbd	1.6mmbd

2. West Coast Production

a) Q. What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PAD V)?

A. Production of crude oil in PAD V averaged 1.06 mbd during the first 4 months of 1976.

3. Imports

a) Q. What is the current level of crude oil and product imports into PAD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content).

A. Current level of crude oil into PAD V by country or origin:

Imports of Crude Oil
(barrels per day)

	January-March (incl.) 1976
Algeria	670
Bolivia	3,033
Canada	110,176
Ecuador	16,154
Gabon	18,429 1/
Indonesia	392,692
Iran	91,011 1/
Libya	451
Malaysia	6,681
Nigeria	945
Oman	11,549
Qatar	8,352 1/
Saudi Arabia	146,011 1/
United Arab Emirates	57,703
Venezuela	3,890 1/
Total	867,747

1/ 50% or more of the oil was of high sulfur content, 1.01% or greater.

3. Imports

a) Q. What is the current level of crude oil and product imports into PAD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content).

A. Refined petroleum products imports into PAD V by country of origin for the first quarter are as follows:

Imports of Refined Petroleum Products
(barrels per day)

	January-March (incl.) 1976
Bahamas	3,363
Bahrain	-
Belgium	-
Brunei	132
Canada	25,297
Guam	-
Hawaii Trade Zone	26,956
Indonesia	231
Iran	-
Japan	-
Kuwait	-
Malaysia	-
Netherlands	1,956
Netherland Antilles	10,835
Nigeria	-
Oman	44
Panama	758
Peru	-
Saudi Arabia	11
Singapore	9,638
Trinidad	2,813
Venezuela	1,670
Yemen	11
Total	83,715

B. Refinery Capacity

1. Q. What is the current refinery capacity and throughput in PAD V?

A. The capacity (January 1, 1976) was 2.5mmbd. The throughput (March 1976) was 1.9mmbd.

2. Q. What are your best current projections for refinery capacity and throughput in PAD V for each year through 1985?

A. Refinery capacity projections in PAD V through 1985 (average capacity for year in thousands of barrels per calendar day).

1976	1977	1978	1979	1980
2,588	2,835	2,874	2,906	2,938

3. Q. What part of the current and projected PAD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

A. Approximately 65% of the current PAD V refinery capacity is capable of processing Alaska crude oil.

II. West Coast Petroleum Demand

A. Q. What is the current demand for crude oil and refined petroleum products in PAD V?

A. The current demand for refined petroleum products in PAD V (April 1976) is 2.4mmbd.

THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

OCT 1 1976

OCT 4 1976

Honorable Henry M. Jackson
Chairman, Interior and
Insular Affairs Committee
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

This is in response to your letters of August 23, cosigned by Senators Magnuson and Stevenson, to me and Admiral Owen W. Siler, Commandant, USCG, concerning the trans-Alaska pipeline system and potential problems associated with the delivery of crude oil from Alaska's North Slope.

The letters enclosed a questionnaire and requested that Admiral Siler and I respond to Question IV, Proposed Responses to the Projected West Coast Surplus.

The DOT has and continues to participate in the completion of the ERC-directed FEA Alaskan Oil Study. It is my understanding that a draft of the study will be made available to you shortly.

Because the issues raised by Question IV of your questionnaire will be addressed by the ERC study, I believe that your desire for a structured examination of those issues will be better served by the study than by a separate response by DOT at this time. However, the DOT remains available to respond to any additional inquiries you may have.

I trust that this arrangement is agreeable to you.

Sincerely,

William T. Coleman, Jr.

OFFICE OF THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

August 24, 1976

..., D. C. 20510

Honorable Henry M. Jackson
United States Senate
Washington, D. C. 20510

Dear Senator Jackson:

Secretary Coleman has asked that I acknowledge receipt of your letter of August 23, co-signed by Senators Magnuson and Stevenson, concerning the trans-Alaska pipeline system and potential problems associated with the delivery of crude oil from Alaska's North Slope.

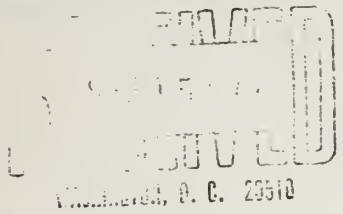
This matter is receiving the immediate attention of the appropriate Departmental officials and you will receive a response as quickly as possible.

Sincerely,

A. B. Virkler Legate
Executive Secretary

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

SEP 14 1976



SEP 14 1976

OFFICE OF THE
ADMINISTRATOR

Dear Senator Jackson:

I am writing in response to your August 23, 1976, letter and questionnaire regarding plans to accommodate new domestic crude oil supplies from the North Slope fields. At this time, the Environmental Protection Agency is unable to provide a substantive response to the questions raised in your inquiry as we have not received formal notice of (and have therefore not studied) any of the alternative plans described in your questionnaire. However, as you know, the Federal Energy Administration has in preparation a detailed study examining many of the issues and questions raised in your letter and questionnaire. EPA has provided financial assistance and technical data to FEA in their development of this study and we understand that a draft will be available for technical review shortly. EPA will be reviewing and commenting on the draft study as soon as it is made available. I would therefore like to defer for the time being any specific responses to your questionnaire in anticipation of FEA's study and our formal response to its content.

The Office of Management & Budget advises that there is no objection to the presentation of this report from the standpoint of the President's program.

If I can be of further assistance, please let me know.

Sincerely yours,

Russell E. Train
Administrator

Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

DEPUTY ADMINISTRATOR

SEP 2 1976

Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

Dear Senator Jackson:

We are now in the final stages of concluding the Energy Resources Council (ERC) study on the transportation and distribution of Alaskan oil. This report has involved a substantial effort by a number of Federal agencies and has included extensive interaction with the States in Petroleum Administration for Defense District (PADD) V and with the major private interests associated with the Alaskan oil. Our current schedule calls for the completion of a first draft of the study by the end of September. This draft would be available to the participating Federal agencies, states and key Congressional Committees for review and comment before a final draft is prepared for transmission to the ERC.

The preparation of a response to the information request submitted by the Senate Interior and Commerce Committee by September 13, will require that the answers be provided without the benefit of a completed first draft of the study. Furthermore, to prepare such a response will require that work on the study be suspended for a week or two while the material required by the questionnaire is being gathered and coordinated. Finally, some of the work on issues, such as air quality impact, has not been completed and will definitely be unavailable prior to the completion of this study.

For these reasons we would like to request that we concentrate our efforts in the near term on completing a first draft of the study which will address most of the questions raised by your committee. This draft will then be transmitted to you and other interested members of the Congress for review and comment along with our response to those questions which the study may not have addressed. Hearings on the issues could then be held once the study is finalized and numerous parties have had an adequate opportunity to review the findings and conclusions.

We will answer by September 13, 1976, the limited number of questions which can be addressed based upon existing information. I hope that you will find this approach satisfactory.

Thank you for your attention and consideration regarding this matter.

Sincerely,

John A. Hill
Deputy Administrator

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

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Honorable Henry M. Jackson
Chairman, Committee on Interior
and Insular Affairs
United States Senate
Washington, D. C. 20510

Dear Mr. Chairman:

This is an interim response to your committee's letter of August 23 in reference to your questionnaire concerning potential problems associated with the delivery of crude oil from Alaska's North Slope.

Information is being obtained to fully respond to your inquiry by September 8.

Sincerely,

Paul Cyr
Director for
Congressional Affairs

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

SEP 14 1976

SEP 14 1976

Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

Dear Senator Jackson:

Enclosed is a partial response to the questions you sent us concerning the disposition of Alaskan oil.

We expect a first draft of our study to be completed within the next few weeks and will complete our responses to your Committee's inquiries at that time.

Sincerely,

John A. Hill
Deputy Administrator

Enclosure

I. West Coast Petroleum Supply

A. Crude Oil

1. Alaska

a) and b) (Questions to a) and b) will be supplied by the Department of Interior.)

c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

FEA forecasts of production from the North Slope are illustrated below:

	(MM B/D)		
	1978	1980	1985
Prudhoe Bay	1.2	1.6	1.6
Other North Slope	---	---	.4 1/

TAPS Capacity

The initial throughput rate for the Trans-Alaska Pipeline System (TAPS) is expected to begin at 600 MB/D in mid-1977, increasing to 1200 MB/D by the beginning of 1978. The rate of flow is projected to advance to 1600 MB/D by 1980, and to 2000 MB/D by 1985 if additional reserves are discovered and market conditions are favorable for transporting the oil.

According to Alyeska officials, to increase capacity of TAPS beyond 1600 MB/D will require three additional pumping stations, cooling equipment, additional tank storage facilities and one additional berth at Valdez. Beyond 2000 MB/D looping will be required.

North Slope Production

The maximum efficient rate of recovery from the Sadlerochit Formation is currently estimated to be approximately 1600 MB/D. 2/ Production beyond this level will, in all liklihood, come from the development of additional reserves from other sources such as Kuparuk River or Lisburne Formations. The Beaufort Sea is also considered a potential source of production in the 1985 timeframe.

An increase in production from the North Slope beyond 1600 MB/D and expansion of pipeline capacity from 1600-2000 MB/D in 1985 is contingent upon a number of highly uncertain factors, including:

- Geological factors pertaining to the discovery of new reserves.
- Market demand for North Slope crude and product yields in PADD V.
- Transportation systems available to move North Slope crude to other regions.
- Comparative crude oil prices.
- The degree of reliance on foreign imports.

1/ FEA forecasts are based on "Developing Production and Price Estimates for Northern Alaska Oil and Gas Supplies" prepared by Research Planning Associates for the Federal Energy Administration October 28, 1975.

2/ FEA forecast for 1980 is based on discussions with State of Alaska officials and industry sources.

2. West Coast Production

a) What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PADD V)?

Production of crude oil for 1975 in PADD V totaled 1.1 MMB/D. A breakdown of production from specific regions is illustrated in the following table.

South Alaska (Cook Inlet)	191
San Joaquin	349
Los Angeles	337
California Coastal Region	196
Kern River	29
Total	1073 MB/D

b) What are your best current projections of production of crude oil in PADD V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

FORECASTS OF ALASKAN CRUDE OIL PRODUCTION
(MB/D)

	1978	1980	1985
TOTAL	1334	1708	1928-2328
AN Alaska North Slope	1200	1600	1600-2000
AS Alaska So. Brooks Range	134	108	328

FORECASTS OF CALIFORNIA CRUDE OIL PRODUCTION
(MB/D)

TOTAL	1094	1211	1393
Onshore	759	733(4)	977 (4)
Offshore (existing state and Federal Leases)	180 (3)	----	----(5)
Elk Hills	155	260	175
OCS (Federal leasing program)	---	218(3)	241(3)

(3) Includes production from existing Federal leases.
(4) Includes off-shore production from state lands.
(5) Assumes continuation of authority to produce Elk Hills.

3. Imports

a) What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulphur content.)

1975 Product Imports into PADD V (6)

Country	MB/D
Canada	21.4
Bahamas	10.8
Netherlands Antilles	12.8
Virgin Islands	1.1
Brazil	1.2
Peru	2.1
Trinidad	3.0
Venezuela	16.8
Bahrain	8.2
Oman	1.7
Indonesia	6.7
Malaysia	2.3
Singapore	13.6
Australia	4.6
Hawaiian Trade Zone	7.4
Other	6.6
	120.3

1975 Crude Oil Imports Into PADD V (6)

Country of Origin	MB/D	Average Sulphur Content
Algeria	1.0	0.13
Bolivia	5.3	1.55
Canada	163.6	0.28
Ecuador	52.7	0.76
Indonesia	295.4	0.08

Country of Origin	B/D	Average Sulphur Content
Iran	105.2	1.48
Libya	7.4	
Malaysia	5.4	
Nigeria	13.8	0.11
Oman	1.4	
Qatar	10.9	
Saudi Arabia	95.6	Light 1.70
		Heavy 2.95
UAE	49.9	
Venezuela	44.1	1.51
Total	851.7	

(5) Bureau of Mines, January - December 1975

b) What are your best current projections of crude oil and product imports into PADD V by country or origin for each year through 1985? (State assumptions behind those projections regarding measures identified in question IV A)

In the 1978-1980 period it is assumed that approximately 500 MB/D of crude oil imports will continue into PADD V. Approximately 350-450 MB/D of imports will be of a light low suphur type comparable to that crude oil now being imported from Indonesia and Canada. This "sweet" crude oil is required due to refinery configuration and product demand slate requirements of several PADD V refineries, notably in Hawaii and the Puget Sound area. Another 50-150 MB/D of imports are expected from Persian Gulf and South American sources due to specialty product requirements and refinery constraints. By 1985 crude oil imports are expected to be in the 300-500 MB/D range with the bulk being Indonesian type crude. Actual imports will be influenced by relative crude oil prices and refinery investment (new capacity and modification) which occurs over the next several years. Product imports should decline to below 100 MB/D from 1978-1980 period and continue at a low level beyond 1980.

B. Refinery Capacity

1. What is the current refinery capacity and throughput in PADD V?

Total PADD V refinery capacity for 1975 totaled 2357 MB/D. Crude runs for the year 1975 were approximately 1980 MB/D, or 84 percent of capacity. (6)

2. What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

PADD V PROJECTED REFINERY CAPACITY AND CRUDE OIL THROUGHPUT
(MB/D)

	AVERAGE ANNUAL CAPACITY (7)	CRUDE OIL THROUGHPUT (8)
1976	2,588	2,056
1977	2,835	-----
1978	2,874	-----
1979	2,906	-----
1980	2,938	2,287
1985	-----	2,875

(7) "Trends in Refinery Capacity and Utilization," Federal Energy Administration June 1976.
(8) Total Refinery throughput would also include natural gas liquids and refinery gains.

3. What part of the current and projected PADD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

The present capability of refineries in PADD V to process Alaskan crude is limited, particularly in the Puget Sound refining center, and in Hawaii, where refineries have been designed to process sweet, light crudes. Only the ARCO refinery in Cherry Point, Washington, (cap 96 MB/D) was built to process crude grades similar to North Slope.

California refineries appear to have greater capability to process North Slope crudes, and crudes of similar grades, particularly as a feedstock mix with lighter, low sulphur crudes. The similarity in refinery yields between composite California crudes and Alaska North Slope crudes in illustrated in the following table:

PADD V
TYPICALLY AVAILABLE CRUDE OILS

	COMPOSITE CALIFORNIA CRUDES	ALASKA NORTH SLOPE
Crude Oil, Gravity - API	19	27
Crude Oil, Sulphur - % weight	1.5	1.0
Straight Run Refinery Yields % volume		
Gasoline	12	18
Midbarrel	26	29
Resid	62	53
Straight Run Sulphur Content % weight		
Gasoline	.04	.01
Midbarrel	.7	.35
Resid	1.9	1.75

Based on a survey of refineries in PADD V region by FEA and information received from industry sources the following preliminary estimates have been developed regarding utilization of North Slope crude oil.

1978 POTENTIAL DISTRIBUTION OF NORTH SLOPE AND FOREIGN IMPORTS IN PADD V
MB/D

Refinery	1975 (CAP) MB/D	1978 ALASKA North Slope	1978 FOREIGN Imports	1975[1] Imports	1975 SWEET Imports	Comments
Los Angeles						
UNION	108	0-50	10-20	45	8	
* ARCO	182	70-100	30-50	65	32	
SOCAL	230	130-190	50-90	150	141	Adds 170 MB/D CAP
SHELL	96	20-35	5-10	21	3	
MOBIL	124	25-30	8-10	14	8	
GULF	52	10-25	10-15	20	5	
DOUGLASS	47	5-25	5-10	11	6	
TEXAS	75	15-20	15-20	15	16	
POWERINE	44	0-5	10-15	20	10	
SUB TOTAL	958	275-480	143-240	361	229	
San Francisco						
*EXXON	88	70-74	0-5	45	3	
SOCAL	190	120-176	30-42	50	24	Adds 150 MB/D CAP
SHELL	100	30-40	0-5	21	2	
TOSCOPETRO	110	0-30	15-20	33	1	Formerly Phillips
UNION	111	0-19	15	?	?	Imports unavailable
SUB TOTAL	599	220-339	45-87	149	30	
Puget Sound						
*ARCO	96	96-98	--	94	43	Designed to run AN
MOBIL	71	10-35	70	48	48	1977/650MB tank 1978 Fuel gas sulfer removal
SHELL	91	0-15	70	71	63	600 MB tanker cost $800-100 ANMIX
TEXACO	78	0-2	70	76	59	Cost 100% AN=$150
SUB TOTAL	336	106-150	210	298	213	
GRAND TOTAL	1893	601-969	298-537	799	472	

Notes:

Includes only those refineries likely to utilize North Slope crude

1. Port of Entry only. These are incomplete crude quality reports but very close to total foreign imports reports which are proprietary.
Large North Slope producers

The continuing need to import low sulphur crudes into San Francisco and Los Angeles refineries will be contingent upon California air quality standards and new desulphurization capacity. The likely behavior of California refineries in their decisions to invest in desulphurization capacity will be determined by comparative costs of alternative crudes to refiners and product slate requirements.

Estimates of the costs associated with converting refineries originally designed to process sweet, light crudes vary from refinery to refinery. It is assumed that these conversions would require a 2-3 year lead time, and would be considered only if Alaskan North Slope crude were priced comparatively lower than foreign imports, and if conversion costs could be recovered through product prices.

II. West Coast Petroleum Demand

A. What is the current demand for crude oil and refined petroleum products in PADD V?

Current (through 1975) demand for crude oil in PADD V totaled 2155MB/D. Demand for products is illustrated in the following table:

1975 PADD V Refinery Production/Product Demand Balance

PRODUCT	PRODUCT[1] MB/D	DEMAND[2] MB/D
Gasoline	987	986
Distillates	231	262
Jet Fuel	234	290
Residual	374	386
Asphalt	59	56
Petrochemical Feedstocks	22	12
Coke	88	32
LPG	33	53
Still Gas	85	79
Other	42	43
	2155	2199

[1]Bureau of Mines, Refinery Report, Form FEA-P320-M-0
[2]FEA National Energy Outlook data base.

b) What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

PADD V DEMAND FOR PETROLEUM
(MB/D)

	1976		1980		1985	
	PRODUCT	CRUDE	PRODUCT	CRUDE	PRODUCT	CRUDE
FEA	2,311	2,056	2,383	2,287	2,966	2,875

Source: 1980, 1985 FEA $13 Reference Case, National Energy Outlook (NEO) data base.

III. West Coast Surplus

Assuming that none of the measures identified in question IV A is implemented:

a) What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V (i.e., the difference between total PADD V production and refinery runs plus addition to stocks)?

Assuming that none of the transportation systems identified in IV A is implemented by the time Alaskan North Slope oil begins to flow, FEA's best estimates of the developing surplus are as follows:

(MB/D)

1978	1979	1985
600	900-1100	700-1300

The supply and demand assumptions from which these estimates were developed are shown in the following table. FEA's high and low surplus projections for 1980 and 1985 are calculated from high and low Alaskan production estimates. These include a foreign import assumption of 500 MB/D. "Low import" surpluses for 1980 and 1985 are calculated by assuming all refiners except the "sweet" refiners - primarily located in Puget Sound - will make conversions to maximize use of domestic production (including North Slope crude) and that the minimum foreign import requirements will be approximately 300 MB/D (equal to the 1975 capacity of West Coast "sweet refineries.")

The actual surplus realized appears to be heavily dependent on the following market factors:

(1) The relative selling price of North Slope crude vis-a-vis foreign imports and other domestic crude oils;
(2) The cost and availability of crude transportation to alternative markets;
(3) Government pricing and regulatory decisions.
(4) Investment decisions by PADD V refineries.

POTENTIAL WEST COAST CRUDE OIL SURPLUS
FEA FORECASTS (PADD V)

	1970	1980	1985
PADD V Production	2,400	2,900	3,300-3,700
Foreign Imports	500	300-500	300-500
TOTAL SUPPLY	2,900	3,200-3,400	3,600-4,200
Demand	2,300	2,300	2,900
PROJECTED EXCESS	600	900-1,100	700-1,300

These forecasts for 1980 and 1985 are based upon the 1976 National Energy Outlook (NEO) which assumes an immediate deregulation of oil and gas and a $13 per barrel price in real dollars. This assumption has the effect of reducing residual fuel oil consumption by utilities and increasing production from California fields by use of enhanced recovery projects. The NEO model does not reflect the fact that the California production would be "heavy" oil for which prices would be lower and markets more limited. Therefore, under current pricing conditions, the NEO demand could be understated and the PADD V supply overstated. This would reduce, but not eliminate, the excess supply shown here.

(b) What are your best current estimates of the net surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 in PADD V (i.e. the difference between PADD V production and refinery runs plus additions to stocks of such crude oil)?

It is expected that most of the estimated surplus of crude oil in PADD V will be crude of similar grades to the North Slope crude. Use of this low gravity, medium sulfur crude in PADD V will be limited for the following reasons:

(1) Limited PADD V demand for "heavy" products, such as residual fuel oil. North Slope oil yields proportionately greater amounts of heavy products in first run distillations;
(2) Additional California crude oil from Elk Hills and offshore regions with sulfur contents equal to or less than North Slope crudes will compete with North Slope crudes;
(3) Refineries designed to run on light, sweet crude will continue to import foreign crudes of similar quality.

Federal Maritime Commission
Washington, D.C. 20573

Office of the Chairman

September 14, 1976

Honorable Henry M. Jackson
United States Senate
Washington, D. C. 20510

SEP 14 1976

Dear Senator Jackson:

I am writing in response to the August 23 letter signed jointly by you and Senators Magnuson and Stevenson, enclosing a questionnaire regarding certain problems relating to the Trans-Alaska Pipeline Authorization Act. You particularly requested our response to Question IV.

The Federal Maritime Commission has no jurisdictional responsibility over the operational and policy matters raised by Question IV or any other portions of the questionnaire. Our regulatory jurisdiction is limited solely to the requirements of Section 311(p) of the Federal Water Pollution Control Act (Public Law 92-500), which requires that any vessel over 300 gross tons operating in United States waters must furnish acceptable evidence of financial responsibility, up to $14,000,000, to cover the cost to the United States for any oil spill removal. When such vessels comply with the foregoing financial responsibility requirements, they are issued Certificates of Financial Responsibility (Oil Pollution) by the Commission as proof of such compliance.

Section 204(c)(3) of the Trans-Alaska Pipeline Authorization Act (P. L. 93-153) recognizes and incorporates the foregoing financial responsibility requirements of the Federal Water Pollution Control Act, and further provides that all vessels must comply with the requirements of that Act before any oil delivered from the Alaska Pipeline is loaded.

Since this agency's regulatory jurisdiction in no way covers the subject matter referred to in Question IV of the questionnaire, we defer to other agencies more directly involved.

The Office of Management and Budget advises that, from the standpoint of the Administration's program, there is no objection to the presentation of these views for the consideration of the Congress.

Sincerely yours,

Karl E. Bakke

Karl E. Bakke
Chairman

SEP 14 1976

FEDERAL POWER COMMISSION
WASHINGTON, D.C. 20426

September 14, 1976

Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

Dear Senator Jackson:

In response to your request of August 23, 1976 we have made an effort to provide all available data on the Sohio Crude Oil Project to which we have access as a result of the El Paso Natural Gas Company proceeding, Docket No. CP75-362. The Standard Oil Company, Ohio (Sohio) commissioned studies evaluating crude oil supply and demand in order to determine the feasibility of its project. Due to the scope and purpose of the hearings to be held by the Senate Committee of Interior and Insular Affairs and Commerce, we are submitting these documents in conjunction with all other data we believe may be helpful to your inquiry.

I. West Coast Petroleum Supply

A. Crude Oil

2. West Coast Production

b) Q. What are your best current projections of production of oil in PADD V other than from the North Slope each year through 1985?

A. DeGolyer and MacNaughton, a consulting firm, prepared a report for Sohio dated January 15, 1975, entitled "Prediction of Oil Production Rates from Petroleum Administration for Defense District V." This report, which is enclosed as Attachment A, is an estimate of oil production from PADD V from 1975 through 1994. The report indicates that production of crude oil in PADD V other than from North Slope will continue to decline through 1985.

Furthermore, as part of the El Paso proceeding, an Environmental Impact Statement was prepared by Sohio Transportation Company in March 1976. Estimates of the

AMERICAN REVOLUTION BICENTENNIAL 1776-1976

crude oil supply are set forth in Table IB. 2-3, which is enclosed as Attachment B.

I. West Coast Petroleum Supply

B. Refinery Capacity

2. Q. What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

A. To meet demand, Sohio anticipates refinery capacity will increase and refinery utilization will improve from 81 percent in 1974 to 90 percent. Refinery capacity additions in 1978 include 350 MBPD, Standard Oil (California), plus 50-150 MBPD for other possible additions, expansion, and debottlenecking. In Table IB. 2-2, enclosed as Attachment C, the projections are set forth. The 1974 refinery capacity has been carried over to 1978 and 1982, despite the fact that a 30-MBPD plant which operated in '74 has been closed. Refinery capacity additions for 1982 were selected to preserve the historical relationship between total demand and refinery. Sohio admits its assumptions are "quite aggressive."

II. West Coast Petroleum Demand

B. Q. What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

A. In March, 1975, the Pace Company Consultants and Engineers, Inc. prepared a report for Sohio entitled "Petroleum Demand in PADD V Through 1995," which is enclosed as Attachment D. It indicates that energy consumption in PADD V is projected to increase at a higher rate than for the United States as a whole. Specifically, it forecasts an average annual increase of 3.6 percent for PADD V for the 1972-1995 period

versus a 2.8 percent rate for the total United States. In its environmental study, Sohio estimates PADD V demand for petroleum to increase from approximately 2.2 MBPD in 1974 to 2.8 MBPD in 1978 and 3.2 MBPD in 1977, 1982. The PACE Company estimates the demand to reach 2.895 MBPD in 1977, 3.251 MBPD in 1980, and 3.339 MBPD in 1985. For the period 1981-1985, the Pace Study anticipates that the importance of LNG from Alaska North Slope, coupled with increasing nuclear power capabilities, will tend to retard petroleum growth, even though North Slope oil will be readily available. PADD V demand growth has historically exceeded growth in the rest of the nation. In this projection, although lower than historic rates, the growth is slightly more than that projected for the entire country.

III. West Coast Surplus

B. Q. What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V?

A. Sohio's estimates of the PADD V surplus is 300-600 MBPD in 1978 and 750-900 MBPD in 1982, as set forth in Attachment B.

According to Sohio's estimate, 600,000 barrels per day of oil will be imported by mid-1977. Mr. Fred Garibaldi, President of Sohio Transportation Company, estimates that 300 to 600 barrels a day of surplus oil will be available by 1978 based on the assumption that 1,200,000 MBPD will be reaching California.

IV. Proposed Responses to the Projected West Coast Surplus

A. 3. The Sohio Crude Oil Project

A. On June 11, 1975, El Paso filed in Docket No. CP75-362 an application, pursuant to Section 7(b) of the Natural Gas Act for

permission to abandon and retire from natural gas service (a) 669.4 miles of existing high pressure gas transmission pipe line, (b) a total of 66,150 compressor horsepower at seven existing compressor stations, and (c) five right-of-way taps, all comprising a part of El Paso's interstate system located in the states of Texas, New Mexico and Arizona. Upon abandonment, the mainline transmission facilities will be converted to the transportation of crude oil as an integral component of the proposed Sohio project.

In order to abandon the gas facilities and thereby convert the gas pipeline to an oil pipeline, El Paso is required to obtain the Commission's authorization under Section 7(b) of the Natural Gas Act. After hearings, the Commission must make a finding that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted or that the present or future public convenience or necessity make such abandonment necessary.

On June 10, 1976, a prehearing conference was held in order to expedite the proceedings. The need for expedition was based on El Paso's allegation that there must be a transportation network established by 1978 to deliver 400 MBPD east of California. On July 7-16, 1976, hearings were held on El Paso's application. On September 8, 1976, the intervenors and Commission Staff filed evidence in this proceeding, and the hearings will reconvene on September 20 to provide for cross-examination. Upon completion of this phase of the hearing, there will be another recess pending the issuance of the final Environmental Impact Statement by the Department of the Interior.

Our information is that the final statement will not be released until March, 1977, at which time the hearings will reconvene to allow the parties to examine the environmental aspects of

the proposed abandonment. The administrative hearings will then be concluded. The parties, Commission counsel, and Presiding Administrative Law Judge are making every effort to act in an expeditious manner so as to render an initial decision on the proposed abandonment by early summer, 1977.

The Sohio Project will involve the leasing of both El Paso's and Southern California Gas Company's (SoCal's) transmission facilities. A portion of the project will consist of certain existing pipeline facilities of SoCal's Texas pipeline system, which are currently being utilized in conjunction with El Paso's pipeline system in the transportation of natural gas from Texas and New Mexico within Southern California. Sohio is currently attempting to obtain the necessary approvals and permits from California.

It is estimated that construction for the Sohio project will take approximately 12-14 months after all necessary permits are obtained. Sohio must not only convert SoCal's and El Paso's existing gas pipeline transmission system to an oil pipeline, it must construct approximately 70 miles of new pipeline from Jal, New Mexico to Midland, Texas. Mr. Travis Petty, President of El Paso Natural Gas Company, estimates that the conversion of the El Paso pipeline will take approximately 6 months.

Sohio does not expect to finance the construction of this project alone. Upon receipt of all Federal approvals, it anticipates that other companies will be partners in the construction of this common carrier pipe line. Sohio's initial studies estimate that the total cost of construction of the crude oil project will be approximately $500,000,000. The cost for converting the El Paso gas pipeline system to an oil pipeline will be about $137.4 million dollars.

Although your questionnaire listed several other "Proposed Responses to the Projected West Coast Surplus," we are unable to provide any relevant information. Northern Tier Pipeline Company intervened in the El Paso proceeding, but they have not introduced any evidence concerning the project.

Due to our lack of direct evidence on the other alternative projects, we are unable to express an opinion on which alternative appears to be the most workable or acceptable. We can state however that the most significant hurdle in our effort to expedite a final decision in the abandonment proceeding is the necessity for awaiting the preparation of a Final Environmental Impact Statement as dictated by the National Environmental Policy Act of 1969. As this environmental review is critical of our evaluation of the project as a whole, the Department of the Interior has made every effort in conjunction with our staff to expedite its preparation. I therefore believe that there is no need for federal legislation to expedite approval of the Sohio Crude Oil Project.

I trust this information will be of some assistance in your inquiry. If I can be of any further help, please do not hesitate to contact me.

Sincerely,

Richard L. Dunham

Richard L. Dunham
Chairman

Attachment A.

DeGolyer and MacNaughton
One Energy Square
Dallas, Texas 75206

Prediction of Oil Production Rates
from
Petroleum Administration for Defense
District V

DeGolyer and MacNaughton
One Energy Squre
Dallas, Texas 75206

Prediction of Oil Production Rates from Petroleum Administration for Defense District V

FOREWORD

Scope of Investigation This report is an estimate of the oil production rates that we think can reasonably be expected from Petroleum Administration for Defense District V (PAD V) from 1975 through 1994. This estimate is based on the extrapolation of historical data from PAD V, data from other oil-producing areas throughout the world, and our best estimate of future exploration and development in PAD V.

Authority This report was authorized by Mr. George J. Abraham, Assistant to Vice President, Oil and Gas Division, The Standard Oil Company (Ohio), hereinafter referred to as the "Company."

Source of Information The information used in this study was obtained from the public information in our files and from our general knowledge of PAD V. We consulted freely with the employees of the Company during the course of this study.

L RESERVES

Oil reserves may be classified as proved, probable, possible, or potential. The reliability of the reserve estimate is greatest when the reserves are classified as "proved," and reliability decreases for probable, possible, and potential reserves. The two classifications of reserves used in this report are at opposite ends of the reliability spectrum and are defined as follows:

Proved reserves are those which have been proved to a high degree of certainty by reason of actual completion, successful testing, or in certain cases by adequate core analyses, and which are defined areally by reasonable geological interpretation of structure and known continuity of oil- or gas-saturated reservoir material. The annual reserves reported by the American Petroleum Institute (API) are in the proved classification.

Potential reserves are those which may be discovered, developed, and produced in the future. There is no assurance that these reserves will be found and produced, and they are generally omitted in discussions with regulatory agencies and financing institutions because of inherent risk in finding and producing them. However, in relatively unexplored basins such as exist in Alaska, these potential reserves are thought to be larger than the proved ultimate recovery actually found to date; therefore, the potential reserves are of great importance in planning the exploration and development of Alaska's natural resources.

Conversely, we think that the current proved ultimate recovery for the state of California is much larger than the potential reserves. Exploration over the past 37 years has contributed only 23 percent of the current proved ultimate recovery for California, but essentially all of the proved ultimate recovery for Alaska has been discovered since 1956.

Because of the different techniques required to forecast proved and potential reserves and the producing rates to be derived therefrom, we have included a separate discussion for each classification.

PROVED RESERVES

Alaska

Based on the API's reserve estimate, as of December 31, 1973, the estimated proved gross ultimate recovery for the fields in the Cook Inlet area was 1.052 billion barrels of crude oil. The cumulative production, as of January 1, 1975, is approximately 609 million barrels, leaving remaining proved reserves of 443 million barrels. This amounts to a producing-life index of approximately 6 years at the current producing rate. Over one-half of the current production is obtained from the McArthur River field. The remainder of the production is obtained from the Swanson River, Middle Ground Shoal, Trading Bay, Granite Point, and Beaver Creek fields. The history of Alaskan oil production, including the North Slope, is shown in Figure 1.

Producing rates from these Cook Inlet area fields have been higher and have been maintained longer than those from fields of similar size in the lower 48 states because the producing rates are not prorated and because of the early injection of water and gas into the reservoirs. As a consequence of the pressure-maintenance schemes and the absence of proration, the fields will exhibit high rates of production followed by rapid declines as the injected water and/or gas moves into the producing wells. Active redrilling programs are in progress in the Swanson River and the McArthur River fields where more than one-half of the ultimate recovery has been produced. We anticipate that the producing rates from the Cook Inlet area will decline at a comparatively low annual rate for the next few years and then will decline at a faster rate as producing wells are abandoned.

Other proved reserves in Alaska are in the Prudhoe Bay field on the North Slope where the current producing rate is less than 8 thousand barrels of oil per day (BOPD). Upon expected completion of the Alyeska Pipeline in mid-1977, the Prudhoe Bay field should produce at a rate of 1.2 million BOPD. We estimate that the peak rate from this field will be approximately 1.5 million BOPD and will be achieved by 1980. The length of time that the rate will remain at peak level is contingent upon reservoir response and operating practices in the Prudhoe Bay field.

The majority of the reserves in Alaska belong in the potential category and are discussed under "Potential Reserves" in this report. These potential reserves substantially increase the predicted production rate for the state of Alaska.

PROVED RESERVES (Contd.)

California

Based on the API's reserve estimate, as of December 31, 1973, the estimated proved gross ultimate recovery for California was 19.919 billion barrels of crude oil. The cumulative production, as of Janaury 1, 1975, is approximately 16.754 billion barrels, leaving remaining proved reserves of 3.165 billion barrels. This amounts to a producing-life index of almost 10 years at the current producing rate. In contrast to Alaska, where over one-half of the production is obtained from one field, the major producing field in California – Wilmington - provides only 20 percent of the state's production, and the combined production of the top five fields yields approximately one-half of California's production. Two of the top five fields are over 50 years old.

Because of the more mature stage of development of the oil and gas reserves in California, the evaluation of the anticipated producing rate from the proved reserves is necessarily more complicated. The California producing rate reached average peaks of approximately 800 thousand BOPD in 1929, 1 million BOPD in 1953, and 1 million BOPD in 1969. Each of these peak producing years was followed by a decline and subsequent increase in producing rate to the next peak. As shown in Figure 2, the peak rate in 1969 was caused by two factors: an increase in oil production from existing fields due to an increase in thermal recovery activity; and attainment of the peak oil rate by the Long Beach Unit which was discovered in 1936 but was not developed and placed on production until 1966. Without the production from these two sources the California production curve would have been on decline in 1969.

The influence of the production from thermal operations and other fields which produce low-gravity crude oil can readily be seen because approximately 54 percent of the 1973 California production has a gravity of 20 degrees API or lower. In contrast, the crude oil with a gravity of 20 degrees API or lower accounted for only 32 percent of the California production in 1961.

The Elk Hills field, commonly referred to as Naval Petroleum Reserve No. 1 (NPR-1), has an estimated ultimate recovery of 1.3 billion barrels of oil. The reserve of the Elk Hills field is included in API's estimate of proved reserves for California. The field is owned by the United States acting through the Navy Department and by Standard Oil Company of California pursuant to a Unit Agreement.

:OVED RESERVES (Contd.)

During World War II, the Elk Hills field was partially developed and produced at a peak rate of 70 thousand BOPD for a short period of time. Current production is restricted by the government to just over 2 thousand BOPD. Cumulative oil production to January 1, 1975, is approximately 284 million barrels.

A joint resolution of the Congress of the United States is required to place the Elk Hills field on production. It has been a firm policy of the Armed Services Committee to restrict production from the field to the current low rate except in times of actual conflict. It is our opinion that this policy will continue in the foreseeable future; therefore, we have projected Elk Hills at the current producing rate. Should the field be placed on production, we think it would be capable of delivering an additional 200 to 250 thousand BOPD to PAD V.

The Tule Elk field on the northern edge of the NPR-1 was discovered by Standard Oil Company of California in 1974 and is now shut in by order of the Federal Court. This field is capable of producing 15 thousand BOPD and ncluded in our projected producing rate for California.

POTENTIAL RESERVES

Alaska

There appears to be little disagreement that the remaining potential reserves for the state of Alaska should be much greater than the reserves that have been found to date. Some of the published estimates of the ultimate resources, in the form of crude oil and natural gas liquids, that will be found in Alaska (onshore and offshore) are as follows:

41 billion barrels -- Mobil Oil Corporation
48 billion barrels – Dr. M. K. Hubbert
86.6 billion barrels -- Division of Geological and Geophysical Survey, Alaska
55-110 billion barrels -- U. S. Geological Survey

Even the lowest estimate of 41 billion barrels is approximately four times greater than the proved reserves currently estimated by the API.

We anticipate that the majority of the potential reserves that will be discovered and placed on production during the 20-year period of our projection will be from the Cook Inlet and North Slope areas of Alaska. It is almost certain that other areas will also contribute to the overall producing rate, but because of the current status of engineering and geological knowledge, the leasing situation, and the existing production, we think that production will be mainly from the Cook Inlet and North Slope areas. It is also possible that production will be discovered and developed in the Gulf of Alaska as well. However, the severe problems encountered in the exploration and development of reserves in the hostile climate of the Gulf of Alaska will probably delay any substantial production from that area, at least during the early years of our projection.

The historical data from the Cook Inlet area indicate a high degree of success in finding oil and in establishing a substantial production rate from the reserves. When compared to other areas in the United States, it is apparent that exploration in the Cook Inlet has been quite successful. The drilling of 194 exploratory tests discovered 1.052 billion barrels of crude oil reserves in the Cook Inlet area. This amounts to approximately 554 barrels of oil per foot of exploratory drilling, or 5.4 million barrels of oil per exploratory well.

POTENTIAL RESERVES (Contd.)

The historical data from the North Slope of Alaska are even more impressive with the discovery of 9.6 billion barrels of oil from the drilling of 70 exploratory wells outside Naval Petroleum Reserve No. 4 (NPR-4). This amounts to 14,333 barrels of oil per foot of exploratory drilling, or 137.1 million barrels per exploratory well.

As a consequence of the successful ventures in the Cook Inlet and on the North Slope, it is apparent that average statistical data for the United States would probably lead to conservative conclusions. However, early exploration in major basins generally discovers the larger amounts of oil; as exploration prospects become poorer, the reserves per foot of exploratory drilling and per exploratory well decrease.

There are other considerations which must be made in evaluating a development schedule of an area such as Alaska. The major consideration is that the hydrocarbons are critically needed by the lower 48 states. Approval of the permit to build the Alyeska Pipeline and increases in the price of oil have already provided increases in exploratory drilling in Alaska. Both the State of Alaska and the United States Federal Government indicate a willingness to lease more land than they have leased in the past.

Our projection of future production rates as shown in Figure 1 will require that these positive factors remain in force. The cumulative oil production from Alaska is estimated to reach 16.5 billion barrels by 1995.

California

There are three sources from which potential reserves might be developed in California. These sources are additional onshore drilling, additional offshore drilling, and increased recovery from currently known fields.

During the past 20 years, a total of 8,315 exploratory wells were drilled in California. Most of the fields discovered during this timespan have been developed sufficiently to place the reserves in the proved category, and

POTENTIAL RESERVES (Contd.)

the fields are currently being produced. The discoveries which have been developed range downward in importance from the Dos Cuadros field, which is currently producing 41 thousand BOPD, to fields which have been abandoned as uneconomical. The API estimates the proved ultimate recovery from these discoveries at over 1.1 billion barrels of crude oil. Based on these historical figures, we would anticipate that approximately 50 million barrels of oil reserves could be added annually by continuing the exploratory drilling effort. However, the possibility of discovering new fields of any important magnitude appears to be remote in view of the intensive efforts of the oil industry over the past 30 years.

There were two sales of Federal leases in the northern California and the Washington-Oregon areas in 1963 and 1964. The sale of 157 leases totaled 900 thousand acres for which the Federal Government received bonuses of $48 million. Fifteen dry holes have been drilled on these leases, and no well has been completed as a producer.

We reviewed the data for the Santa Maria basin, the Ventura-Santa Barbara basin, and the Santa Monica Bay and Long Beach-Huntington Beach areas of the southern California basin; from these data, we find little encouragement to believe that the production-decline rate for the State of California will be arrested by drilling additional exploratory wells.

The main reason for our pessimistic outlook on future discoveries offshore from California is that we anticipate that the offshore areas will be plagued with many problems including delays because of environmental considerations, extremely high costs caused by expensive deep-water drilling, and shallow reservoirs which are quite difficult to develop economically from offshore platforms. One of the overriding considerations in our evaluation is that many of the fields along the coast exhibit low recovery factors and are marginally profitable on land. It is expected that these same formations will be encountered offshore where exploration and development costs will be greater, so there is little reason to believe that the reserves could be produced profitably.

Based on the API's estimate of proved reserves, the state of California will recover only 24.3 percent of its original oil in place

POTENTIAL RESERVES (Contd.)

while the United States is expected to recover 31.6 percent of its original oil in place. The lower recovery factor for California is caused to a great degree by the large percentage of the more viscous, low-gravity crude oil that is produced there. Secondary and tertiary recovery techniques that are currently in operation have increased the estimated recovery factor for California from an even lower number. Additional recovery techniques that are as yet unknown may aid in increasing the recovery from known fields in California.

Our estimated oil production rates for the state of California are shown in Figure 2. The cumulative oil production from California is estimated to reach 22.5 billion barrels by 1995. This production schedule requires that approximately 5.7 billion barrels of oil be produced during the 20-year forecast period. Since our forecast assumes only minimal production from the Elk Hills field, at least nother 3.5 billion barrels of oil which are now classified as potential must be reclassified as proved and produced during the forecast period. This additional oil is expected to be added to the proved ultimate recovery by revision of the reserve estimates for existing fields, by extension of the limits of existing fields, and from new fields such as the Santa Ynez Unit which will be placed on production. We consider 3.5 billion barrels to be a reasonable figure because the ultimate recovery for California was increased by 5.9 billion barrels during the 19-year period from 1955 through 1973. Over 90 percent of the 5.9 billion barrels was added to the ultimate recovery from increases due to revisions in reserve estimates and to the extension of existing fields. The remaining reserves were added by new reservoir and new field discoveries. It is therefore apparent that the percentage of the California production rate from the potential reserves should rise from zero to over 75 percent in the 20-year period.

SUMMARY and CONCLUSIONS

In our opinion, the oil production from PAD V will continue to decrease at a nominal rate until 1977 when we estimate the Alyeska Pipeline will be completed and the Prudhoe Bay field will be placed on production. The initial producing rate from Prudhoe Bay should increase the PAD V producing rate to over 2.2 million BOPD. which is double the current rate. We then look for the production rate from Alaska to increase to 3 million BOPD by 1989, raising the total PAD V production rate to over 3.7 million BOPD. Our estimate of the future oil production rate from PAD V is shown in Table 1.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

SIGNED: Janaury 15, 1975

TABLE I

HISTORY and FORECAST of CRUDE OIL PRODUCTION

Year	AVERAGE ANNUAL PRODUCTION RATE			
	Alaska		California	
	Northern Alaska	Total State	Total State	PAD V Total
	(Thousands of Barrels of Oil Per Day)			
1955	0	0	972	972
1956	0	0	958	959
1957	0	0	929	931
1958	0	0	859	860
1959	0	1	842	847
1960	0	2	831	836
1961	0	17	818	839
1962	0	28	809	841
1963	0	29	822	854
1964	0	30	818	851
1965	0	30	866	898
1966	0	39	941	986
1967	0	79	986	1,073
1968	0	181	1,024	1,217
1969	1	204	1,027	1,238
197	3	229	1,019	1,254
197.	3	216	982	1,204
1972	3	202	948	1,150
1973	3	200	920	1,122
1974	6	200	885	1,085
1975	8	190	894	1,084
1976	8	194	882	1,076
1977	600	801	878	1,679
1978	1,200	1,408	863	2,271
1979	1,200	1,415	859	2,274
1980	1,500	1,704	861	2,565
1981	1,500	1,805	857	2,662
1982	1,700	2,112	843	2,955
1983	1,775	2,297	837	3,134
1984	1,850	2,487	812	3,299
1985	1,925	2,678	812	3,490
1986	1,950	2,750	791	3,541
1987	1,975	2,837	770	3,607
1988	2,000	2,937	745	3,682
1989	2,000	3,000	725	3,725
1990	2,000	3,000	703	3,703
1991	2,000	3,000	683	3,683
1992	2,000	3,000	666	3,666
1993	2,000	3,000	647	3,647
1994	2,000	3,000	631	3,631
CUMULATIVE PRODUCTION		(Billions of Barrels)		
January 1, 1995	11.4	16.5	22.5	39.0
January 1, 1975	0	0.6	16.8	17.4
EXPECTED PRODUCTION, NEXT 20 YEARS	11.4	15.9	5.7	21.6

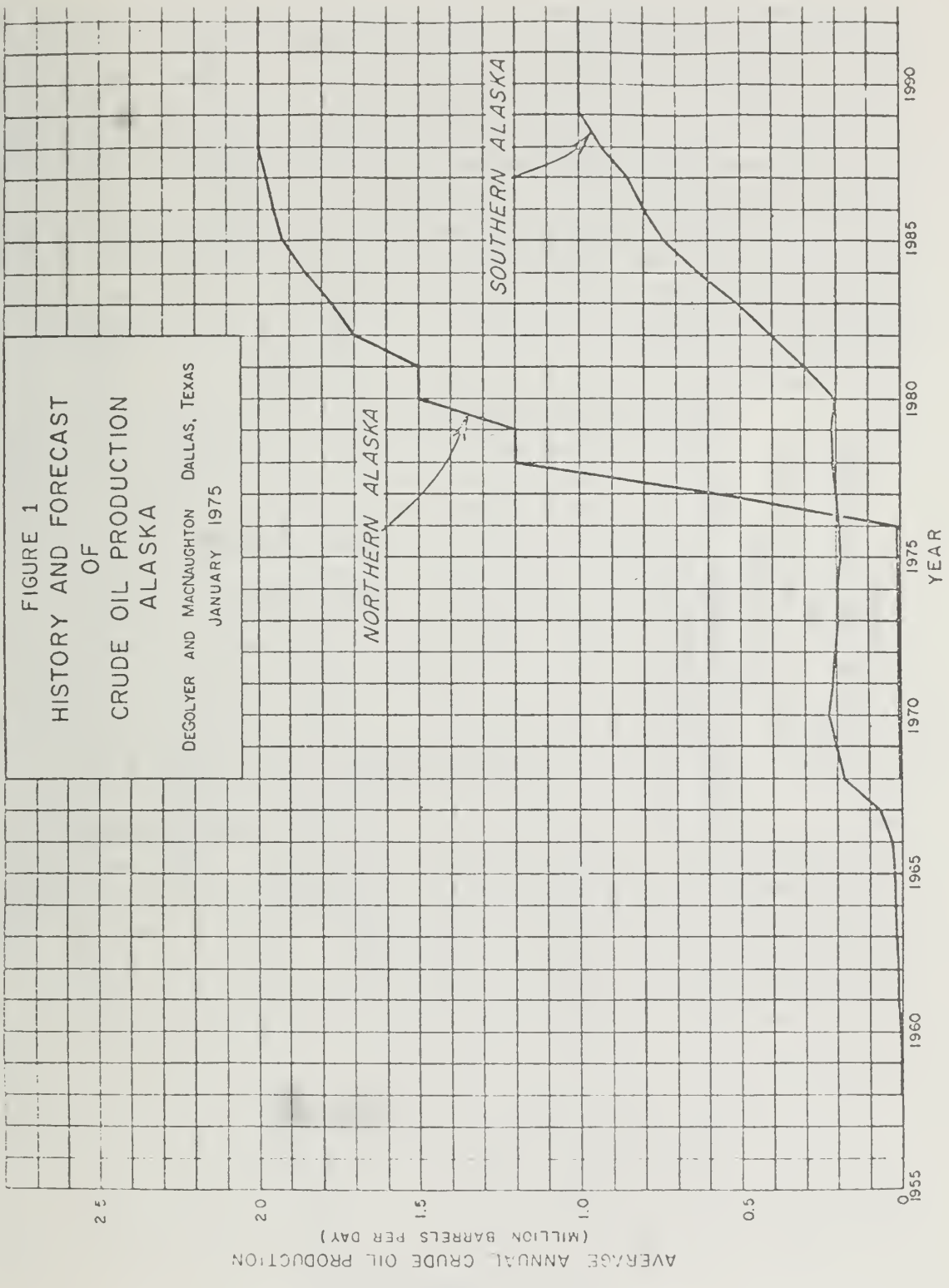


FIGURE 1
HISTORY AND FORECAST
OF
CRUDE OIL PRODUCTION
ALASKA
DEGOLYER AND MACNAUGHTON DALLAS, TEXAS
JANUARY 1975
NORTHERN ALASKA
SOUTHERN ALASKA
AVERAGE ANNUAL CRUDE OIL PRODUCTION
(MILLION BARRELS PER DAY)
0
0.5
1.0
1.5
2.0
2.5
1955
1960
1965
1970
1975
1980
1985
1990
YEAR

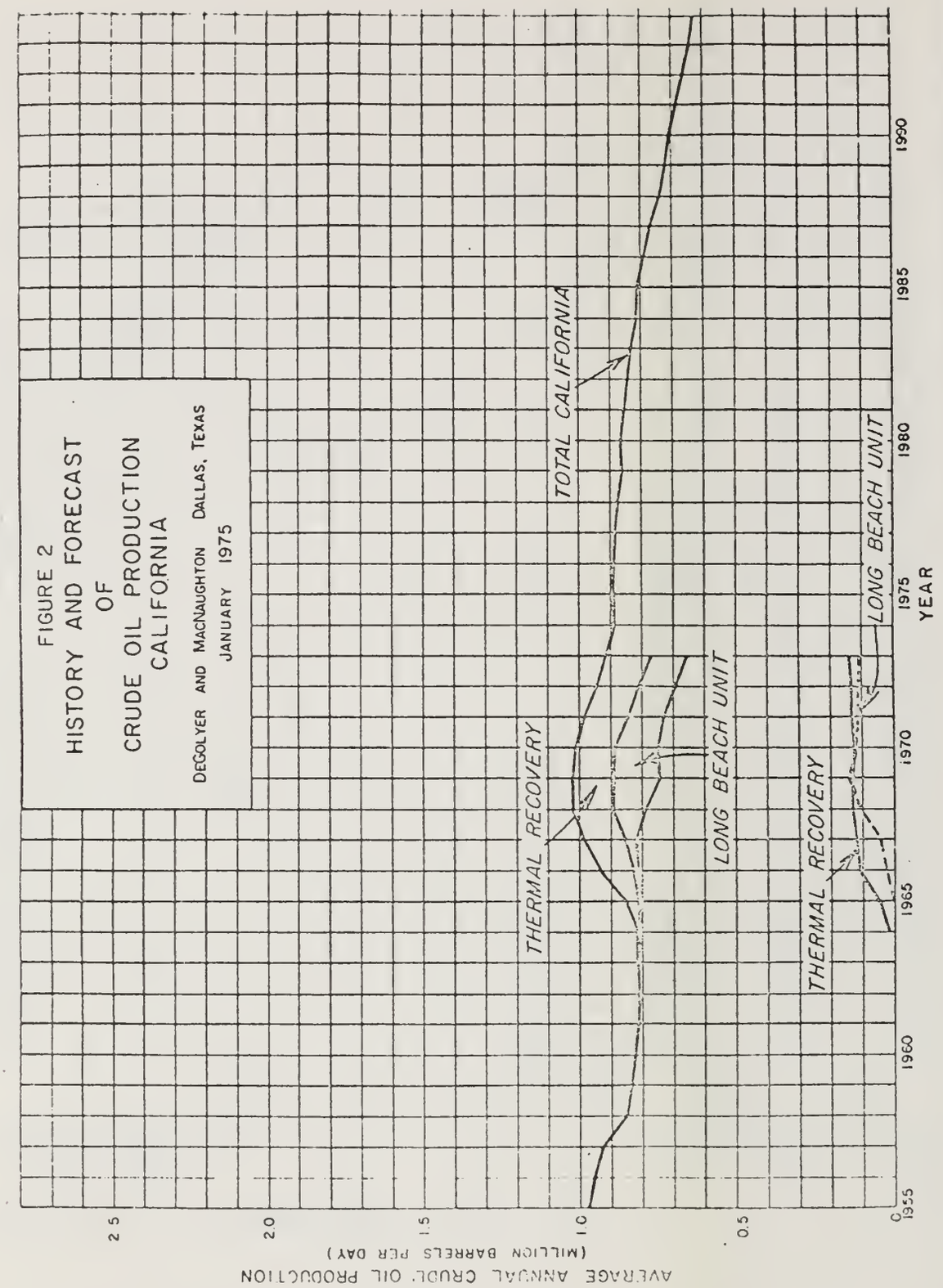


FIGURE 2
HISTORY AND FORECAST
OF
CRUDE OIL PRODUCTION
CALIFORNIA
DEGOLYER AND MACNAUGHTON DALLAS, TEXAS
JANUARY 1975
TOTAL CALIFORNIA
THERMAL RECOVERY
LONG BEACH UNIT
LONG BEACH UNIT
THERMAL RECOVERY
AVERAGE ANNUAL CRUDE OIL PRODUCTION
(MILLION BARRELS PER DAY)
0
0.5
1.0
1.5
2.0
2.5
1955
1960
1965
1970
1975
1980
1985
1990
YEAR

Docket No. CP75-362
Attachment B.

Table 1B.2-3. CRUDE SUPPLY PADD V. Thousand Barrels Per Day.

	1974	1978	1982
Crude Processed	1900	2475-2550	2800-2900
Crude Source			
California Production	890	850	750
Alaskan Cook Inlet	190	150	150
Other U. S. Districts	45	-	-
Canadian Imports	190	100-0	-
Offshore			
Persian Gulf and other sour crude	310	-	-
Indonesian and African sweet crude	275	450-550	500
New California Production			
Offshore	-	0-75	350-400
Elk Hills	-	100-250	-
Alaskan North Slope	-	1200	1800-2000
Total Crude Available for Processing	1900	2850-3075	3600-3800
West Coast Crude Surplus		300-600	750-900

Docket No. CP75-362

Attachment C.

Table 1B.2-2. COMPARISON OF REFINING AND PRODUCT IMPORTS. Thousand Barrels Per Day.

	1974	1978	1982
Demand			
PADD V Petroleum Products	2200	2800	3200
Supply			
Refining Capacity	2354	2354	2800
Forecasted New Capacity	--	400-500E	300-400E
Total Capacity	2354	2750-2850	3100-3200
Crude Processed at 81% in 1974 (at 90% in 1978-82)	1900	2475-2550	2800-2900
Net Product Imports, Natural Gas Liquids, etc., to meet demand	300	250-325	300-400
Total Supply	2200	2800	3200

Attachment D.

THE PACE COMPANY CONSULTANTS & ENGINEERS, INC. 3700 BUFFALO SPEEDWAY
P.O. BOX 53495 HOUSTON, TEXAS 77052 AC 713 626-2020 CABLE: PACECO-HOUSTON TELEX 76-2515

PETROLEUM DEMAND IN PADD 5 THROUGH 1995

Prepared for

THE STANDARD OIL COMPANY (OHIO)

For Pace

S. F. Culberson

B. N. C. Fenton

P. W. Fields

March, 1975

PETROLEUM DEMAND IN PADD 5 THROUGH 1995

INTRODUCTION

Petroleum demand projections for five western states - California, Oregon, Washington, Arizona and Nevada - have been developed through 1995. In this discussion, this area is referred to as Petroleum Administration for Defense District (PADD) 5, although two PADD 5 states, Alaska and Hawaii, have been excluded from the analysis.

The basis for this work was the comprehensive Pace study, "Energy and Hydrocarbons in the United States to 1985". This study was completed in February 1974 and required about 20 man-years of effort. Completion of the study occurred after the Arab Oil Embargo and consideration was given to higher oil costs and the probable shift to alternate fuels. There were approximately 50 subscribers to this Energy Study representing a cross-section of the energy producing and consuming industries. Included were oil and chemical companies, utilities, major manufacturing firms, and several governmental agencies. The study was continually reviewed with clients during preparation and has been formally reviewed with most of them following completion. Their comments and criticisms have been considered and taken into account in our current work.

With this background as a starting point, PADD 5 projections were reviewed and updated in light of overall developments which have occurred since publication of the Energy Study. Particular emphasis was placed on the specific effects of these factors on the western states. Selected personal contacts were made to insure a high degree of thoroughness and accuracy.

Description of the Pace Energy/Hydrocarbon Model and a detailed illustration of the methodology used in forecasting energy consumption are included in the Appendix.

SUMMARY

Energy consumption in PADD 5 is projected to increase at a higher rate than for the United States as a whole. Specifically, our "most probable" forecast indicates an average annual increase of 3.6 percent for PADD 5 for the 1972-1995 period versus a 2.8 percent rate for the total U.S. This trend is based on anticipated continuing population migration into the region and analyses of lifestyle and economic circumstances unique to PADD 5.

Within this framework of total energy requirements, most probable PADD 5 petroleum demand (expressed in terms of thousand barrels of crude oil per day) is shown in the following table:

PADD 5 PETROLEUM DEMAND (MBPD as COE)	
1969	1732
1972	1918
1974	2150
1977	2790
1980	3176
1985	3226
1990	3670
1995	4076

This forecast is depicted graphically in Figure 1. Occurrences of any of several potential developments can alter this most probable forecast. The more important of these "sensitivities" are noted and quantified in the body of this report.

The significant trends, developments and assumptions contributing to our forecast for PADD 5 petroleum demand are indicated in the following summations for individual time periods:

1969 - 1973

This was basically a period of steady, sustained growth. Although there were variations above and below the "trend line", there were no serious disruptions until late in 1973, when the Arab Oil Embargo and unprecedented increases in oil prices occurred.

Late 1973 - 1974

The Arab Oil Embargo and higher energy prices created a period of general turmoil and uncertainty. One of the most immediate reactions was a marked drop in energy and hence petroleum demand. This is clearly illustrated in Figure 1.

1975 - 1977

The strong growth anticipated during this period primarily reflects increasing usage of residual fuel oil for power generation. This will become necessary because there is insufficient time for nuclear power to develop significantly, and gas supplies from outside PADD 5 will decline. Environmental problems will restrict coal usage. The impact of smaller, more efficient automobiles will not be fully realized.

1978 - 1980

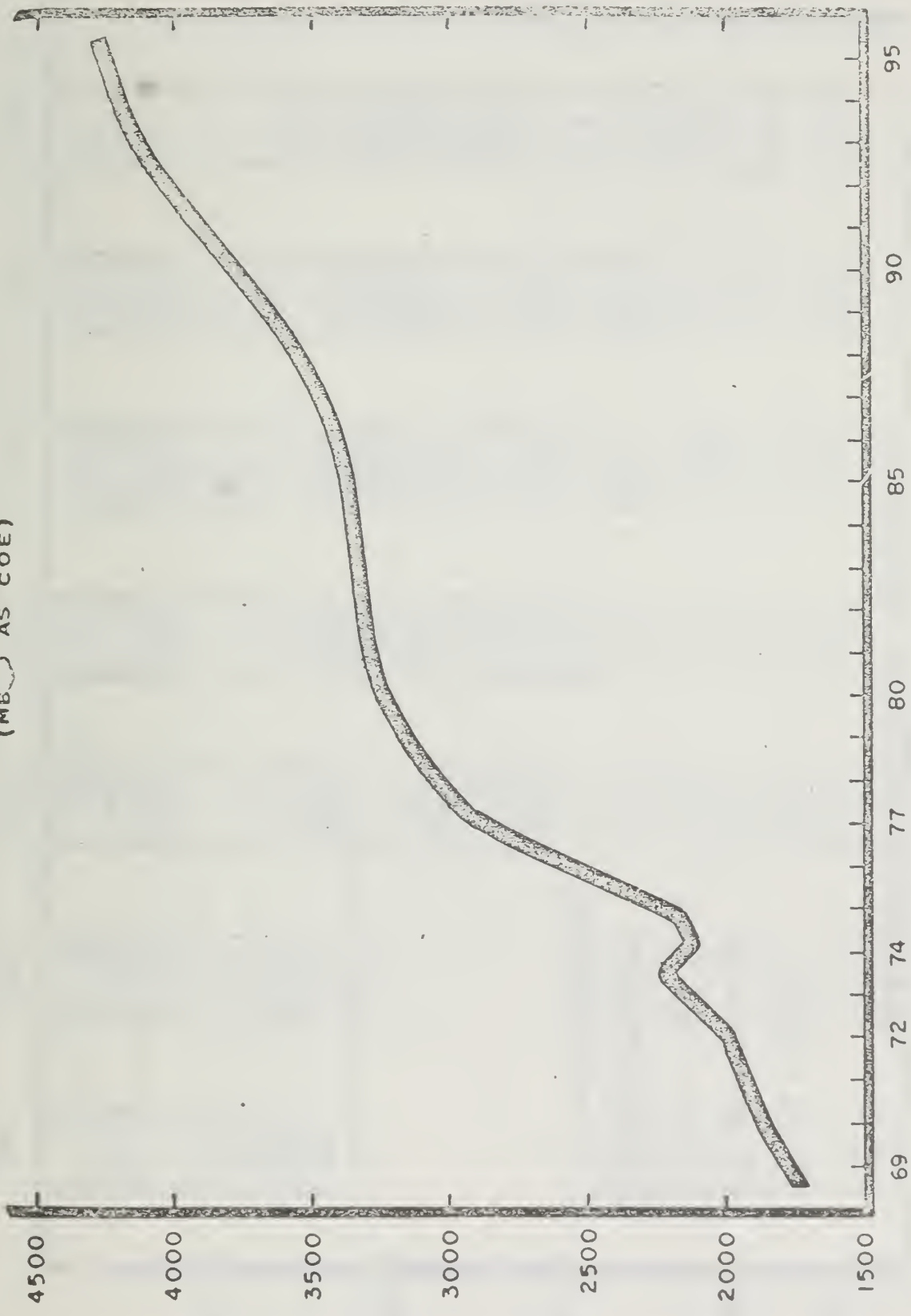
Continuation of the pattern established in the previous period is expected. Some increase in per-household travel has been assumed, but this will be at least partially offset by continuing trends to small cars and better fuel economy. Importation of Alaska North Slope crude oil should be initiated during this period. This will lead to a favorable oil supply position on the West Coast.

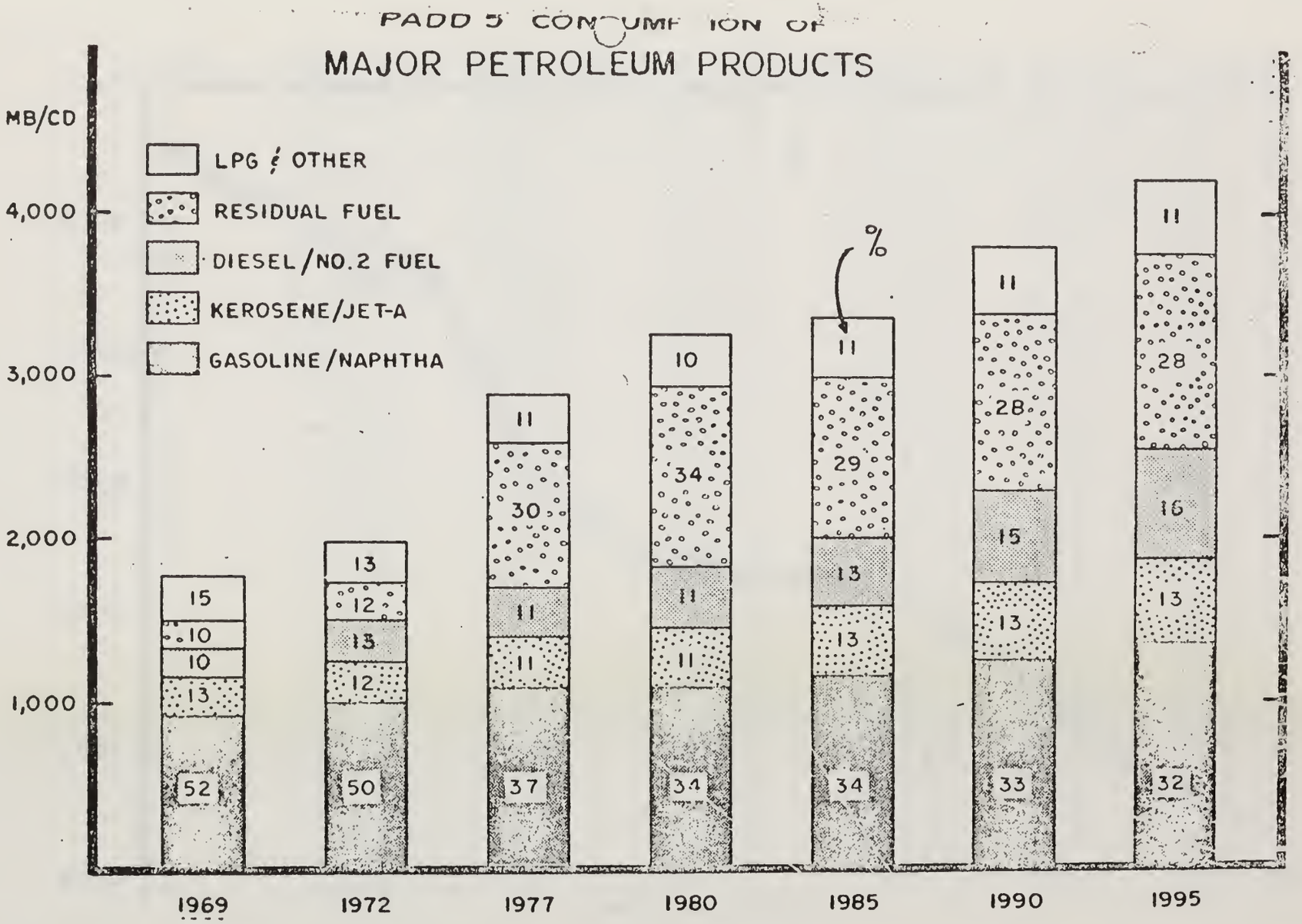
1981 - 1985

The most significant development anticipated during this period is the importation into PADD 5 of liquefied natural gas (LNG) from the Alaska North Slope. This new energy supply coupled with sharply increasing nuclear power capabilities will tend to retard petroleum growth, even though North Slope oil will be readily available.

1985 - 1995

PADD 5 demand for petroleum is expected to resume a higher, but still moderate growth, averaging about 2.4 percent annually. The emergence of a petrochemical industry on the West Coast and continuing increases in travel will be contributing factors. Also, the supply of North Slope LNG has been assumed to remain constant at the 1981-85 level.


(MB_) AS COE)
4500
4000
3500
3000
2500
2000
1500
69
72
74
77
80
85
90
95


PADD 5 CONSUMPTION OF
MAJOR PETROLEUM PRODUCTS
MB/CD
4,000
3,000
2,000
1,000
LPG & OTHER
RESIDUAL FUEL
DIESEL/NO.2 FUEL
KEROSENE/JET-A
GASOLINE/NAPHTHA
%
15
10
10
13
52
13
12
13
12
50
11
30
11
11
37
10
34
11
11
34
11
29
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1969
1972
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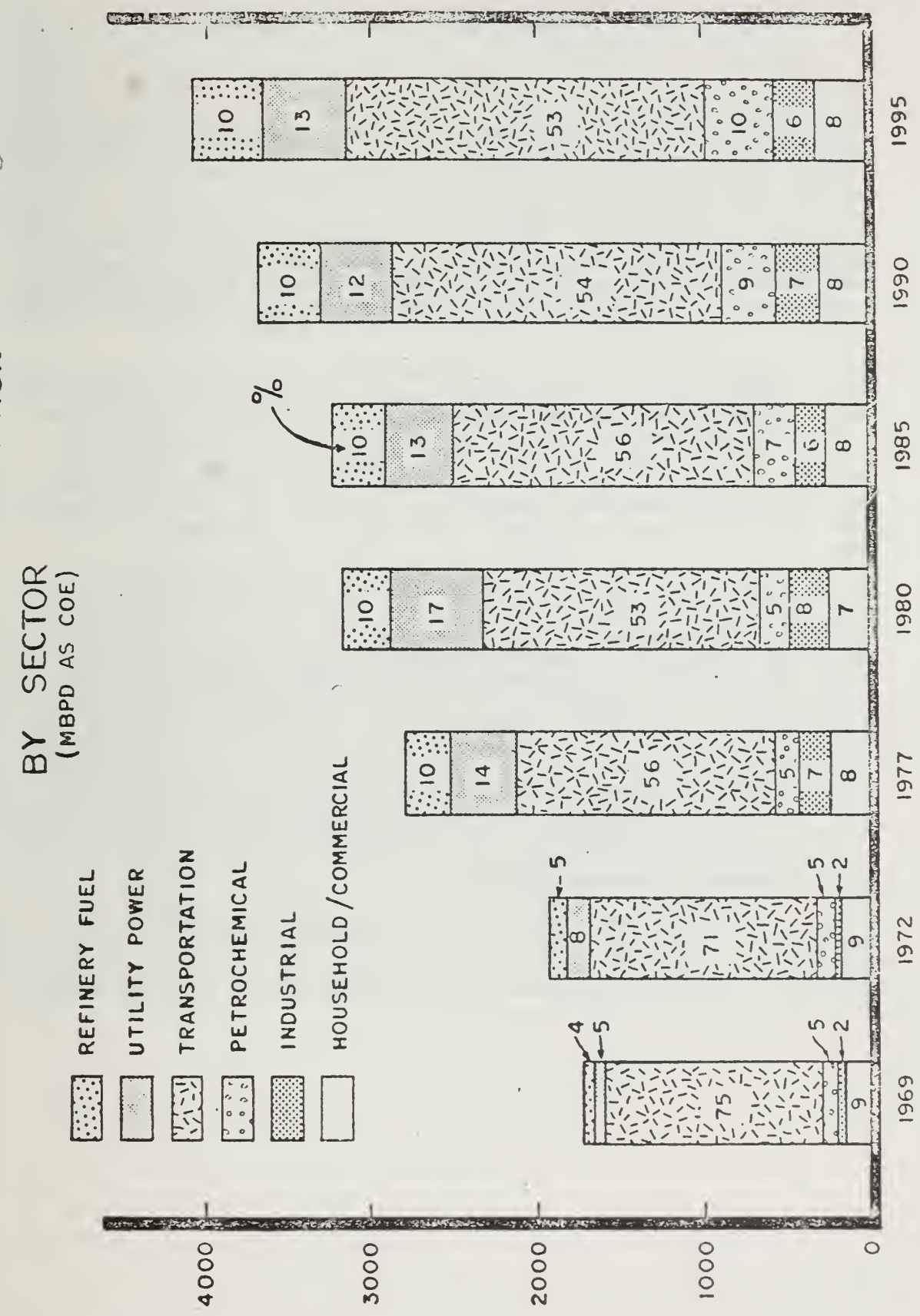
1995


PADD 5 PETROLEUM CONSUMPTION
BY SECTOR
(MBPD AS COE)
REFINERY FUEL
UTILITY POWER
TRANSPORTATION
PETROCHEMICAL
INDUSTRIAL
HOUSEHOLD/COMMERCIAL
%
4000
3000
2000
1000
0
1969
1972
1977
1980
1985
1990
1995
10
13
53
10
6
8
10
12
54
9
7
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13
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71
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2
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4
5
5
2
9
75

DISCUSSION

GENERAL

Historically, more than adequate supplies of low cost energy have been available to meet U.S. demands. Forecasts were demand oriented, i.e., energy consumption was limited only by the capacity of industry and the public to consume it. There was seldom any concern that the basic raw materials would be available. In recent years, there has been increasing concern about our ability to meet future demands. It was widely accepted that supply limitations would restrict growth. Now, with current energy costs, there are indications that demand growth is being depressed. Incentive for increased efficiency of energy use will also tend to suppress energy demand. As a consequence, supply capabilities may no longer be the limiting factor in energy growth.

These factors have been taken into account in our reassessment of future energy demand. Since major uncertainties still exist in energy supply (specific volumes of domestic crude and gas, governmental policy, price and supply of imports, technology developments, etc.), consideration must be given to the effects of a large number of possibilities before arriving at a forecast of the "most probable" situation. Due to logistics and the regulatory system, the U.S. energy economy must be considered as a number of geographical regions (new gas in Texas is not necessarily available for the home owner in California).

In our Energy Study, Pace accounted for these variable factors by developing a comprehensive computer model that simulates the complete energy/hydrocarbon system in seven geographical areas of the U.S. and arrives at the overall balance by summation of the regional balances. Regional demand forecasts for energy and non-energetic hydrocarbons (petrochemicals) have been prepared for each sector of the economy. For a given set of assumptions on supply of specific hydrocarbons, governmental policy, etc., the Model determines the optimum method of operation of the petrochemical, refining, gas, and utility industries; the amount of new capacity required in these industries; the optimum location, product slate, feedstock and energy source for new plants, and any shortages of various hydrocarbons with the possible alternates or imports required to offset the shortages. The economic optimum amounts of synthetic gas manufacture and other energy conversion processing required to close the supply and demand balance were determined.

Pace's approach has been to determine where energy has been used in the past and then to estimate the specific changes in lifestyle that will occur in response to shortages and higher costs for energy. We have further recognized that these changes will be gradual and the maximum effects of energy conservation will not be realized for some time.

Each solution of the Energy/Hydrocarbon Model provides a complete balance for energy and the petrochemical industry for a specified set of conditions. In the Energy Study, three possible forecasts were presented: high, low, and median or "most probable". In our work for this project, we have prepared one "most probable" case. Although forecasts are required only for PADD 5, we first analyzed the total United States, then broke out and presented PADD 5 on a consistent basis. The other geographical areas are not detailed here.

BASIS

The forecasts presented in this report were developed within the framework defined by a number of conditions which we have assumed will prevail throughout the period covered. The more significant and important of these are:

1. A slowdown in the economy has been assumed through 1977 due to inflation and balance of trade problems associated with paying for high-cost oil imports. Our energy balances imply by 1980 improvement in the economy relative to the 1974-1977 period. We have further assumed that a severe recession will not occur.

2. Imported oil at $7-$10 per barrel will stimulate development of other energy sources, e.g., coal, nuclear, natural gas, hydropower, etc. These will be developed to the extent practically possible. Oil will close the gap to meet total energy demand.

3. Oil priced at $7 per barrel provides incentive for reduced and/or more efficient consumption. Time is required for the full effect of these savings to be realized. Oil at $10 per barrel would thus provide little additional reduction in demand.

4. The demand for energy in PADD 5 will tend to grow at a rate higher than that for the remainder of the U.S. Continuing population migration and industrial development (petrochemicals as a prime example) will be contributing factors. Along with this increase in demand, PADD 5 should be in a better long range oil supply position than the rest of the country. This will result directly from the impact of Alaskan North Slope Oil.

5. We have been generally optimistic regarding other energy supply sources. If they should be available at lower than assumed levels, then a higher oil demand will result. (The effects are quantified in the discussion of "Sensitivities").

Historical data for two years, 1969 and 1972, are included with our projections. These years were selected for specific reasons:

1. Complete compilation and analysis of 1969 data were done for the Energy Study. The time and effort required to develop comparable data for 1970 would not be justified by the results which would not show significant difference.

2. We developed 1972 energy balances specifically for this current work because it represents the last "normal" year for which complete data are available. Both 1973 and 1974 are atypical discontinuous years because of the effects of shortages, sharp price escalations, Arab Oil Embargo, price controls, and various political and emotional influences. Use of these years could in some respects be misleading rather than informative.

PADD 5 ENERGY CONSUMPTION TRENDS

The first step in deteriming demand for petroleum is to establish a projection for total energy usage. Within this overall framework, the demand for individual fuels is estimated through analysis of the inter-related factors affecting them and the sectors of the economy in which they are consumed. Our estimate of most probable PADD 5 total energy usage is summarized in the following table. Total United States demand is also shown to provide perspective. Since this energy comprises several types of fuel, the total is expressed as thousands of barrels of crude oil per day (MBPD), in order to provide a consistent means of comparison and discussion.

ENERGY CONSUMPTION
(MBPD)*

	PADD 5	Total U.S.
1969	3739	29994
1972	4202	33556
1977	5236	40590
1980	5881	44550
1985	6922	50160
1990	8104	56280
1995	9403	62690

*1 MBPD Crude Oil Equivalent = 2.135 trillion BTU per year.

The growth rates represented by these projections, along with historical perspective are:

ENERGY CONSUMPTION
AVERAGE ANNUAL GROWTH RATE (%)

	United States	PADD 5
1960 - 1969	4.3	N.A.
1969 - 1972	3.8	4.0
1972 - 1977	3.9	4.5
1977 - 1980	3.2	4.0
1980 - 1985	2.3	3.2
1990 - 1995	2.2	3.0
1972 - 1995	2.8	3.6

In September 1974, the National Petroleum Council (NPC), an industry advisory body to the government, released a new set of U.S. energy demand projections. Since this group is widely recognized, the trends indicated by their forecasts are presented for comparison with those developed by Pace:

U.S. ENERGY CONSUMPTION
.1972-1985 AVERAGE ANNUAL GROWTH

NPC High Demand Case	3.6%
NPC Low Demand Case	2.6%
NPC Median Case	3.1%
Pace Most Probable	3.1%

fact that the Pace Most Probable and NPC Median Cases forecast the same annual growth is coincidental. Our forecasts are based on detailed analysis and build-up of end use sectors; at the time of this writing, NPC's end-use pattern and supporting data were not available to us.

Energy Consumption by Fuel Type

As noted previously, forecasts of total energy consumption are based on demand forecasts, followed by evaluation of all available energy sources and analysis of the accommodations required in consuming areas. Our resultant breakdown of PADD 5 energy consumption by fuel type is shown as follows:

PADD 5 ENERGY CONSUMPTION BY FUEL TYPE
(MBPD as COE)

	Solid Fuels	Petroleum	Gas	*Hydropower	Nuclear	Total
1969	35	1732	1240	702	30	3739
1972	113	1918	1336	771	64	4202
1977	204	2790	960	1128	154	5236
1980	275	3176	982	1263	185	5881
1985	343	3226	1257	1361	735	6922
1990	541	3670	1123	1540	1230	8104
1995	695	4076	1071	1868	1693	9403

*Includes geothermal and electricity imports.

Although the trends through 1995 in PADD 5 energy contributed by various fuel types do not appear dramatic, it must be realized that the amounts of energy under consideration are enormous, and even slight percentage shifts represent very significant quantities. The most significant trends discernible for each fuel type are:

1. Solid Fuels - Coal is seen to exhibit quite sharp growth from a low base. Usage will be in thermal applications, i.e., "under boilers" in both the industrial and utility power sectors. This will occur to a greater extent in the northern PADD 5 states (Oregon and Washington) than in California and will be in the form of low-BTU gas derived from coal as well as direct burning of coal.

2. Petroleum - Consumption increases through 1995, but the growth rate fluctuates. This reflects the influence of varying growth rates in the transportation sector, discussed later. Also, con-

tributing are variations in consumption of other forms of energy; these combine to affect petroleum because it is the "swing" increment to meet total energy demand.

3. Gas - Consumption declines sharply through 1977, reflecting declining availability, particularly from West Texas, then levels through 1980 in response to higher prices. During the period to 1977, usage of gas is largely discontinued in heavy industry and in utility power generation.

   Alaskan North Slope LNG has been assumed to be brought into PADD 5 between 1980 and 1985 (3.5 million cubic ft./day, equal to 653 MBPD, COE). This gas will penetrate the industrial and utility power sectors for several years. Total supply then is expected to gradually decline as imports from PADD 3 (Texas) decrease. Texas gas will be consumed in preferred uses (i.e., home heating and light industry) in other areas of the United States.

4. Hydropower/Geothermal/Electricity Imports - Steady increase in importation of electricity from New Mexico and Utah is predicted, because California in particular wants to avoid, to the extent possible, the environmental effects of burning coal and/or oil. Hydropower will exhibit only minor growth since most economic sites have already been developed. Geothermal will show an increase from a low base, but will not be a major factor in electric power generation.

5. Nuclear - From a low base, nuclear power is expected to show dramatic growth, especially in the post-1980 period. To date, only one West Coast nuclear plant has been postponed or cancelled and with this deletion, we have assumed that the proposed schedule will be fairly closely followed through 1985. The additions beyond 1985 represent Pace's forecast. Much of the new capacity will probably be added at existing sites to minimize the environmental effects. Nuclear power will account for 12 percent of total PADD 5 energy in 1980 and 17 percent by 1995.

Energy Consumption by Sector

The same energy data in the preceding tables are shown in the following table on a consumption-by-sector basis. As in consumption-by-fuel type, the trends may appear subtle, but are significant because of the enormous amounts of energy represented.

PADD 5 ENERGY CONSUMPTION BY SECTOR
(MBPD as COE)

	Household/ Commercial	Industrial	*Petro-chemical	Transpor-tation	Utility Power	Refinery Fuel	Total
1969	612	334	138	1320	1150	185	3739
1972	678	349	164	1391	1415	205	4202
1977	784	504	217	1604	1957	271	5237
1980	833	574	234	1721	2213	305	5880
1985	925	642	314	1867	2854	320	6922
1990	1012	713	420	2035	3557	367	8104
1995	1102	787	512	2213	4381	408	9403

*Includes all energy minerals used as raw materials.

Among the more important assumptions and trends reflected in each energy-consuming sector are:

1. Household/Commercial - Relatively steady growth is expected, related to household formations. Some improvements in efficiency--more insulation, higher thermostatic settings, more careful use of lighting, etc.--are assumed. A shift to electric heating is anticipated. Currently, in PADD 5, about 20 percent of residences are heated electrically; we project that 35 percent of new units will install electric heat.

2. Industrial - Relatively steady growth in energy consumption in this sector is also forecast. The rate, however, will be lower than the historical trend, reflecting more efficient energy usage as a result of higher costs.

3. Petrochemical - Energy availability in general and petroleum availability in particular should lead to development of a West Coast petrochemical industry. Long lead times are required, however, to allow for establishment of satellite plants required for justification of large basic olefins/aromatics facilities. We have assumed the following schedule for the number of ethylene plants (one billion pounds per year capacity) operational in PADD 5:

1980 - 0
1985 - 0
1990 - 5
1995 - 7

The principal feedstock will be heavy naphtha and gas oil (No. 2 Fuel Oil).

Transportation - Consumption of energy in the transportation sector primarily reflects gasoline demand. Most of the apparent sharp increase between 1972 and 1977 occurred in 1973, when gasoline usage increased over 5 percent. Between 1974 and 1977, growth of energy consumption in transportation will be restricted by:

- Increasing fuel efficiency in automobiles
- No increase in total travel because of a generally depressed economy
- Lower speed limits
- Increasing percentage of small cars
- More passengers per car (car-pools) in intra-city travel

Between 1977 and 1980, we have assumed a 0.5 percent annual increase in per household travel, and beyond 1980 a 1 per cent per capita growth. This increase, however, will tend to be partially offset by continuing efforts by the automobile manufacturers to improve fuel economy.

Utility Power - Prior to the Arab Oil Embargo and the advent of higher energy costs, most forecasts of electricity growth were in the 6-7 percent range. As a result of more efficient electricity usage, both in industry and homes, and lack of convincing evidence of a stronger shift to electric heating, we have adopted considerably lower forecasts. The figures shown in the preceding table represented growth rates of about 6 percent from 1972 through 1980 and about 4.5 percent thereafter.

PADD 5 PETROLEUM DEMAND

The petroleum consumption forecasts for PADD 5 may be broken down into individual refined products and into consumption by sector, just as was done for total energy. A wide range of projections are possible; some of these can be calculated with a higher degree of certainty than others. For example, gasoline has

essentially only one use, and no other fuel can be substituted in that use. Thus, it is possible to define its consumption within relatively narrow limits set by vehicle population, fuel economy and mileage driven. (These variables, of course, in turn are dependent upon additional assumptions discussed in the Appendix.) In contrast, most other energy products can be used in more than one area. Also, many energy-consuming sectors can be served by alternate fuels. For example, a home can be heated with gas, fuel oil, or electricity. The electricity can be generated from any of the fossil fuels, nuclear or hydropower.

The following tables summarize our PADD 5 projections of petroleum by major products and by consuming sector. These are consistent with the energy data presented previously, i.e., the "most probable" situation. The major developments which must occur in order for this forecast to occur are noted after the tables. Also, the degree to which the forecasts would change under certain specific developments ("sensitivities") are also discussed.

PADD 5 CONSUMPTION OF
MAJOR PETROLEUM PRODUCTS
(MBPD)

	Gasoline/ Naphtha	Kerosene/ Jet A	Diesel No. 2 Fuel	Residual Fuel	LPG & Other	Total
1969	924	233	170	173	268	1768
1972	997	249	256	228	255	1985
1977	1088	314	304	874	315	2895
1980	1089	369	365	1104	324	3251
1985	1156	421	425	969	368	3339
1990	1239	480	560	1089	419	3787
1995	1340	530	671	1186	475	4202

PADD 5 PETROLEUM CONSUMPTION BY SECTOR
(MBPD as COE)

	Household/ Commercial	Industrial	Petro- chemical	Transpor- tation	Utility Power	Refinery Fuel	Total
1969	167	32	97	1294	78	64	1732
1972	176	30	105	1361	149	97	1918
1977	221	189	155	1563	391	271	2790
1980	233	241	166	1677	554	305	3176
1985	254	180	237	1827	408	320	3226
1990	280	257	334	1995	437	367	3670
1995	305	253	417	2178	515	408	4076

Many of the major assumptions supporting these tables and the resultant significant overall trends are similar to those applicable to the U.S. as a whole. The factors which are significantly different or unique to PADD 5 are:

1. Small cars constitute a higher percentage of the total than for the rest of the country. This is expected to continue to be the case.

2. Jet fuel usage is proportionally higher than for the U.S. as a whole, primarily because of long distance plane service to and from the West Coast.

3. Residual fuel oil will continue to be used in power stations because of strong environmental objections to coal in most of PADD 5. The availability of oil on the West Coast relative to the rest of the country will tend to encourage its use for power generation. Development of nuclear power will impede growth in residual fuel however.

PETROLEUM DEMAND SENSITIVITIES

Potential developments can significantly alter the "most probable" forecasts. Often, the ultimate resolution of these uncertainties is political rather than economic or logical, making them all the more difficult to predict. The only realistic way to take them into account is to define the effect on the "most probable" case if each event occurs/does not occur or develops significantly different from the "most probable". The major sensitivities which can alter PADD 5 petroleum demand and their potential effects are summarized below. If the alternate forecast prevails in any sensitivity (or combination of two or more), the indicated difference in energy supply must essentially be made up by additional petroleum consumption. The only alternative is lower energy demand/consumption. As noted previously, we have been generally optimistic in regard to alternate supplies of energy. Our "most probable" petroleum demand, obtained by difference is then, in effect, a low case.

SENSITIVITY ANALYSIS

Influencing Factor	Forecast	MBPD as COE 1985	1995
Nuclear Power	Most Probable	735	1693
	Alternate	614	1233
	Petroleum Increase	121	460
Alaskan North Slope LNG	Most Probable	653	653
	Alternate	0	0
	Petroleum Increase	653	653
Geothermal Energy	Most Probable	164	656
	Alternate	99	264
	Petroleum Increase	65	392
Lower Coal Usage	Most Probable	343	695
	Alternate	200	300
	Petroleum Increase	143	395
Gasoline Demand			
1. Effect of full NO_x penalty of 0.4 g/mile	Most Probable	1017	1185
	Alternate	1293	1568
	Petroleum Increase	276	383
2. Effect of less car-pooling (1.5 passengers/car vs. 1.6 on intracity travel)	Most Probable	1017	1185
	Alternate	1133	1333
	Petroleum Increase	116	148
3. Effect of fewer small cars: 40% small, 40% intermediate, 20% large, versus original 50:35:15 level assumed.	Most Probable	1017	1185
	Alternate	1180	1406
	Petroleum Increase	163	221

APPENDIX

THE PACE ENERGY/HYDROCARBON MODEL

This linear programming model is the basic tool used in developing energy balances. It is large and comprehensive--about 2,000 equations and 5,000 variables. The model provides a simulation of the entire U.S. energy/hydrocarbon system, on total and regional bases. Seven U.S. geographical areas are considered; Western Europe and Western Hemisphere areas outside continental United States are also included.

The following basic data are incorporated in the model:

1. Energy and hydrocarbon supplies and costs.

2. Product specifications for refined petroleum products and petrochemicals.

3. Processing and conversion capacity and costs for the refining, petrochemical, LNG, SNG, natural gas, and utility power industries.

4. Transportation costs for refined products, crude oil, petrochemical, electric power, and natural gas between seven U.S. regions, and for products moved between Europe, the Caribbean, and the U.S. mainland.

5. Energy demands by sector and region for the U.S. and on an overall basis for Europe and other Western Hemisphere (petroleum only). These are inputs to the Energy/Hydrocarbon Model and the Model selects the power combination of energy sources to match demands in an optimum manner within the assigned restraints.

ENERGY FORECASTING

Energy is used, directly and indirectly, by people. We have, therefore, for this forecast and in our original Energy Study, related domestic energy usage to the number of households, as our basic forecasting parameter. Other parameters such as GNP or population could have been used. We believe, however, that relating energy consumption to the rate of household formation offers several advantages.

There is a broad relationship between energy use and GNP. Changing efficiencies of energy utilization, amount of disposable income, and economic conditions, however, distort the correlation. Relating energy use to households and lifestyles should not be as subject to these distortions.

The relationship to households takes into account population change and migrations as well as total population. The elements of population change are subject to large variations in the birth rate. Due to these variations, the age distribution of the population is constantly changing. The basic unit for the organization of the population is the household, which is a family, or a group of non-related individuals, living together. Household formation by individuals is a function of age and economic circumstances.

Although the number of households is affected by past changes in the birth rate, it is almost independent of current changes because children do not form separate households. For this reason, a prediction of households to 1995, made on population statistics to 1970, involves few assumptions about the birth rate during the period and can therefore, have a higher chance of accuracy then a prediction of population.

There are other advantages in the use of a per household, rather than a per capita basis. Many energy consuming activities are dependent on households rather than individuals. For example, space heating, which uses about 20 percent of all energy, is clearly a household function. Automobile ownership also correlates to households, and can be organized to show families with one car, two or more cars, etc.

Annual estimates of the number of households in each state are published by the Bureau of the Census. Projections of the number of households on a national total basis, and of population by states, to the year 1990, have also been published. A judicious blend of the national total households projection and the population by states projection, can produce a households by states projection. Table A-1 provides actual and projected households through 1995 for the United States and PADD 5.

GASOLINE DEMAND FORECASTS

This discussion is intended to illustrate the general techniques and in-depth detail used in developing forecasts. Gasoline has been selected as an example because it is the most important refined product and the factors affecting its usage are relatively easy to visualize and understand. The same degree of thoroughness was utilized in analyzing each product/sector making up our overall energy forecasts.

Methodology and Assumptions

About 72 percent of all gasoline consumed in the U.S. is used by automobiles, 20 percent by light trucks, and 8 percent by buses, heavy trucks, airplanes, non-highway vehicles and distribution losses. The percentage consumed by automobiles and light trucks has been rising because diesel fuel has been replacing gasoline used by buses, trucks and non-highway vehicles and because the use of aviation gasoline has been declining. This trend will continue. We predict that automobiles and light trucks will use about 96 percent of all gasoline by 1995.

Federal vehicle emission regulations apply to both automobiles and light trucks, and, therefore, to almost all of the gasoline used in 1995. Fuel consumption by automobiles is a function of three main variables:

1. The number of automobiles in use
2. The average number of miles driven by these automobiles
3. The average fuel economy of the automobiles in terms of miles per gallon

Combining factors 1 and 2 gives the total number of automobile miles driven, and combining this with the average number of occupants in an automobile gives the total number of passenger miles travelled. Passengers may also travel in vehicles other than automobiles. Trips between cities may be made by airplane, bus or train and trips within cities may be made by bus or railroad (surface and underground). However, automobiles dominate passenger travel. During 1973, 86.3 percent of all passenger miles travelled between cities and 94.1 percent of all passenger miles within cities were by automobile. The share of automobile transportation has increased steadily at the expense of other modes. User-operated transportation is more flexible and convenient than mass transportation and has become economically feasible for an increasing fraction of the U.S. population.

User-operated transportation also consumes more energy per passenger than does mass transportation. The average U.S. automobile requires 5 to 6 times as much energy per passenger as a bus, and 6 to 7 times as much energy as a commuter train. Even with the smallest reasonable automobile, the factor is about 2:1 versus a bus. An increase in the cost of gasoline, and other transportation fuels, will cause three deviations from past trends:

1. Total passenger travel will grow less rapidly
2. Increased use will be made of buses and trains, which use less energy per passenger mile
3. The size and weight of new automobiles will decline--there is an almost linear relationship between weight and fuel economy.

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Our approach to forecasting automobile gasoline use has, therefore, been as follows:

STEP 1

Total passenger miles travelled is projected for trips between cities and within cities. To do this, the historical trend was calculated on a per household basis, giving a factor which has been increasing steadily. The higher cost of fuel can be recognized in terms of reduced future growth in per household travel. We estimte that, during the next few years, there will be little if any growth as the U.S. economy adapts to higher energy costs. However, growth will be resumed before 1980, but at a lower rate of increase than prevailed before 1974.

STEP 2

The share of automobile travel in total passenger miles is projected by taking due account of increased use of buses and railroads.

STEP 3

Vehicle miles for automobiles are calculated by compounding passenger miles with the vehicle occupancy factor. We do not anticipate a significant change in the occupancy factor for vehicles on journeys between cities. However, within cities the factor was averaging only 1.4 occupants per vehicle until 1973. Car pooling, stimulated by the gasoline shortage, has increased this factor and we predict that it will stablize at 1.6 by 1980.

STEP 4

The average fuel use of automobiles is projected. Our method for making this calculation takes into account changes due to the growing number of small cars in new registrations, the weight of new safety features such as collision protection bumpers, the effect of vehicle emission regulations on fuel economy and reduced speed limits. The change due to the vehicle emission regulations is calculated in terms of the increase over the level which would have prevailed without the emission controls. The largest increase is caused by the engine modifications required to meet the nitrogen oxides (NO_x) emission regulations. Under federal law, 1978 model cars must release, on average, no more than 0.4 grams NO_x per mile travelled. The only such regulation currently in effect is in Cal-

ifornia where state law limits NO_x emissions to 2.0 grams per mile on 1975 model cars. Compared to uncontrolled cars, the limit of 2.0 grams per mile increases fuel usage by 5 percent. Although there are uncertainties until the control technology is developed, research engineers in the automobile industries have estimated that the limit of 0.4 grams per mile may increase fuel usage by an additional 30 percent. There is some doubt that the 0.4 grams per mile limit is needed to insure adequate air quality, and no doubt that a 30 percent increase in fuel usage would be an undesirable drain on the U.S. economy. We have assumed, in calculating the "most probable" demand case that the federal law will be changed to a standard of 2.0 grams per mile on all 1978 model cars. We have also calculated the gasoline demand for the situation if the law is unchanged and a 30 percent penalty applies.

STEP 5

Gasoline demand is calculated by combining automobile miles travelled with average miles per gallon. This procedure is illustrated by the following changes predicted in the various parameters:

	1969	1972	1980	1985	1980	1995
48 Mainland States	actual	actual	projected	projected	projected	projected
Total Travel:						
Billion passenger miles	1846	2100	2453	2801	3153	3566
Automobile Travel:						
Billion passenter miles	1629	1880	2099	2292	2550	2850
Billion Automobile Miles:						
by small cars	59.5	145.9	356.8	442.9	503.3	562.9
intermediates	308.6	355.4	422.3	456.1	504.8	564.3
large cars	489.8	502.7	265.9	236.0	253.9	282.8
Total	858	1004	1045	1135	1262	1410
Average Fuel Usage:						
Miles per gallon	13.79	13.79	12.68	13.36	14.02	14.74

Tables A-2 through A-8 give additional information on intra- and inter-state mileage and specific factors which were used in calculating gasoline consumption for automobiles and light trucks.

The greatest change predicted is in the size of cars. Small cars (4 and 6 cylinder models weighing under 3000 pounds) are expected to increase their

share of automobile miles driven from 6.9 percent of the 1969 total to about 40 percent of the 1995 total at the expense of large cars which decline from 57.1 percent to 20 percent during the same period. Thus, our forecast implies that the main adjustment to accommodate higher fuel costs will be trends toward smaller cars, such as those already favored in Europe and Japan, and that adoption of alternate methods of transportation will be, proportionately, much less significant.

A corresponding method is used to predict fuel use by light trucks, taking into account the effect of vehicle emission regulations and speed limits. In the case of fuel used by buses, heavy trucks and non-highway vehicles, where gasoline is being replaced by diesel fuel, we first predict total fuel use then gasoline's share. As a result, diesel oil demand increases rapidly (by 2.84 times from 1969 to 1995 while total gasoline increases only 1.53 times).

So far we have discussed only the projection of total U.S. gasoline demand. It is also necessary to divide this among the various regions of the U.S. PADD 5 (the states of Arizona, California, Nevada, Oregon, and Washington) has been taking a rising share of national total energy consumption due to migration of population to this area from other states. This migration is expected to continue in the future, but at a declining rate. A projection has been made by the Bureau of the Census, and we have used this to predict growth in the number of households in the western states. As a fraction of the national total, this is expected to change as follows:

	Percent
1950 actual	10.2
1960 actual	12.2
1970 actual	14.3
1980 projected	14.9
1985 projected	15.1
1990 projected	15.4
1995 projected	15.6

Historically, change in the West Coast share of total transportation fuel has followed change in the West Coast share of total households, and this relationship can be used to predict the future West Coast transportation fuel demand. It is also necessary to allow for the recent trend towards small automobiles in western states. During the past five years, small cars, both imports and domestic models, have been a larger fraction of new car registrations on the West Coast than nationwide. In the first half of 1974, small cars amounted to 48 percent of West Coast sales. This has reduced the West Coast's share of total gasoline consumption; our projection considers this car size effect. We expect the preference for small cars in western states to continue and,

based on discussions with U.S. automobile manufacturers, we predict that automobile population and new car sales will stablize by 1980 at about 40 percent small cars nationwide and 50 percent on the West Coast.

It should be noted that the miles per gallon (mpg) figures shown above are lower than some recent published estimates that U.S. automobiles averaged about 14 mpg in 1974 (1).

We have developed mpg figures on a consistent basis as follows. The Department of Transportation publishes estimates of automobile vehicle travel each year in "Highway Statistics". By comparing these with gasoline sales, it is possible to calculate average miles per gallon for automobiles. The calculation does, however, involve certain assumptions about fuel use by light trucks, heavy trucks and buses, so that the method is, to some degree, based upon our judgment. The result for 1972 using our procedure does agree with the 1972 mpg estimate in the Federal Highway Department Annual Highway Statistics as published in the report referenced below (2). Our analysis indicates that the average mpg of U.S. automobiles continued to decline in 1973 and 1974 to a level near 12 mpg. This has been confirmed by discussions with automobile manufacturers.

Recently the Environmental Protection Agency has started testing the fuel economy of new automobiles. The weighted (by sales) average based on these tests shows a significantly higher average for automobile miles per gallon than the calculation based on the Department of Transportation statistics. There are two possible reasons for the discrepancy.

1. The estimate of automobile miles driven is less than the actual level.

2. Automobile efficiency in the hands of the general public is less than in the tests conducted by the Environmental Protection Agency.

Probably both factors contribute to the discrepancy. We do not consider that this invalidates our procedure for projecting automobile gasoline demand which is based on correlations developed from historical Department of Transportation data. If there is a bias in automobile miles driven estimates made by the Department of Transportation, it is consistent in all of the data, historical and projected.

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(1) "Department of Transportation News", October 25, 1974. This source quoted from a joint report submitted to the Congress by the U.S. Department of Transportation and the Environmental Protection Agency--"Potential for Motor Vehicle Fuel Economy Improvement".

(2) Reference footnote (1), Figure 3, page 20.

The combination of factors in Tables A-2 through A-8 and our calculation procedure thus lead to the mpg values shown. Even with significant improvements in fuel economy, the average mpg only changes slowly starting from the low 1974 base.

OTHER FORECASTS

As previously noted, other products and sectors were forecast in detail comparable to that illustrated for gasoline. Examples of major parameters considered in these analyses are:

Household/Commercial Sector

The projection takes into account:

1. New construction, i.e., number of old and new units in use at any given time in each PADD.

2. Effect on future new construction of the gradual elimination of sub-standard housing, i.e., less replacement will be required in the future in this category.

3. Trend toward smaller homes and multi-unit homes (apartments and townhouses) associated with changes in the age distribution of the population and economic conditions, i.e., less space heating energy per unit will be required.

4. Savings in space heating fuel possible from improved insulation of new and old structures.

5. Change in the choice of fuel for space heating, i.e., to electric resistance heating and heat pumps, from combustion of gas or fuel oil.

6. Saturation in the use of air-conditioning and other household appliances.

Industrial Sector

This sector has been segregated to show the following elements, which have been projected independently.

1. Fuel used on natural gas leases and in gas processing plants

2. Fuel used in cement plants

3. Power used in electrochemical processes (aluminum, magnesium, and caustic/chlorine production)

4. Power used for uranium isotope separation

5. Fuel and power used in oil refineries

6. Natural gas used by federal and state government agencies

7. Power used by generating utilities ("inter-departmental") and by federal and state governmental agencies

8. All fuel and power not separately accounted above

Utility Power Sector

Power generated is the sum of the following items:

1. Demand for power in the Household/Commercial Sector

2. Demand for power in the Transportation Sector

3. Demand for power in the Industrial Sector

4. Transmission and distribution losses estimated at 10 percent of total power generated

Power is supplied from the following sources:

1. Hydropower - the projection is based on a survey of the potential of developed and undeveloped sites made by the Federal Power Commission.

2. Nuclear Power - through 1985, the projection is based on announced committments by generating utilities and after 1985 it is based on estimates of construction capability and the base power demand (being capital intensive, nuclear power would not be used to supply a variable daily demand).

3. Geothermal Power - the projection is an estimate made by Pace on the basis of discussions with several West Coast generating utilities.

4. Fossil Fuel Power - this is the balance required to meet the demand. The fuels used are assigned on the basis of:

   a) Flexibility of existing plant with regard to fuel type
   b) Environmental limits on fuel sulfur content
   c) Availability - this influences fuel choice for new capacity
   d) Plant load factor - some power must be generated to meet peak demands in equipment operated less than 1000 hours per year. Gas turbines, which require natural gas or distillate oil fuel, are preferred for this service.

Raw Materials and Petrochemical

This sector covers consumption of energy minerals for purposes other than fuel and power. There are two exceptions:

1. Asphalt, following the convention of the U.S. Bureau of Mines, is counted in the Household/Commerical Sector.

2. Lubricants used by transportation vehicles are counted in the Transportation Sector.

All items included in this sector are reported in the Industrial Sector by the U.S. Bureau of Mines:

1. Consumption of coal to make metallurgical coke.

2. Consumption of raw material, fuel and power to make:

   a) Ammonia
   b) Methanol
   c) Other synthesis gas derivatives
   d) Ethylene
   e) Propylene (for chemical derivatives only)
   f) Butylenes (for chemical derivatives only)
   g) Butadiene
   H) Acetylene
   i) Benzene
   j) Toluene (for chemical derivatives only)
   k) C_8 Aromatics (for chemical derivatives only)
   l) C_9 Aromatics (for chemical derivatives only)

3. Consumption of raw material as:

   a) Petroleum derived solvents
   b) Carbon black feedstock
   c) Petroleum coke
   d) Miscellaenous petroleum based chemicals
   e) Miscellaneous natural gas based chemicals
   f) Industrial lubricants
   g) Wax

While this sector includes all of the energy contained in minerals used as raw materials and the fuel and power used in making the primary petrochemicals listed under item 2, it does not include the energy used in the further processing of these primary materials to products for final consumption. This is counted in the Industrial Sector.

Table A-1

NUMBER OF HOUSEHOLDS

	Thousand Households*			
	50 States	48 States**	PADD 5	PADD 5 Percent 50 States
Actual				
1969	62073	61797	8882	14.31
1970	63143	62862	9027	14.30
1971	64293	64002	9232	14.36
1972	65464	65164	9440	14.42
Projected				
1977	71878	71528	10580	14.72
1980	75847	75468	11309	14.91
1985	82426	81996	12471	15.13
1990	88260	87780	13557	15.36
1995	94970	94430	14768	15.55

* Number applicable to July 1 of each year.

** Excludes Alaska and Hawaii.

Notes for Table A-1

A household is a separate residence, maintained by a single person or group of persons living together. Many energy consuming activities are related to the operation of a household so that change in the number of households can be used to predict future energy requirements.

By dividing the population into five-year age segments, probability factors can be calculated for the formation of households in the following categories:

1. Husband-wife pairs
2. Male head of household (no wife present)
3. Female head of household (no husband present)
4. Male individuals (living alone)
5. Female individuals (living alone)

Extrapolating the probability factors from past trends, future household formation can be calculated from population statistics. This calculation is almost unaffected by the future birthrate up to 20 years ahead in time because the probability of household formation under the age of 20 is very small.

To segregate PADD 5 from the national total, it is necessary to take interstate migration into account. PADD 5 has been gaining population from the other states for many years. The projection in the table was based on a study by the Bureau of the Census which predicted future interstate migration from a continuation of the 1960-70 trend. This trend shows a declining migration effect with time.

Table A-2

TRAVEL WITHIN CITIES

	Billion Passenger Miles						Thousand Households (July 1)	Miles per Household
	Automobiles	Buses	Street cars	Trolley-cars	Subway/Surface Rail	Total		
Actual:								
1969	652	31	1	1	23	708	62073	11406
1970	692	30	1	1	21	745	63143	11799
1971	735	29	1	1	21	787	64293	12241
1972	795	28	1	1	21	846	65464	12923
Estimated:								
1973	830	28	1	1	22	882	66656	13232
Projected:								
1977	873	44	1	1	32	951	71878	13230
1980	910	63	1	1	44	1091	75487	13430
1985	969	116	1	1	76	1163	82426	14110
1990	1075	131	1	1	101	1309	88260	14830
1995	1198	148	1	1	133	1481	94970	15590
	As Percent of Total							
Actual:								
1969	92.1	4.4	0.1	0.1	3.3	100.0		
1970	92.9	4.0	0.1	0.1	2.9	100.0		
1971	93.4	3.7	0.1	0.1	2.7	100.0		
1972	94.0	3.3	0.1	0.1	2.5	100.0		
Estimated:								
1973	94.1	3.2	0.1	0.1	2.5	100.0		
Projected:								
1977	91.8	4.6	0.1	0.1	3.4	100.0		
1980	89.3	6.2	0.1	0.1	4.3	100.0		
1985	83.3	10.0	0.1	0.1	6.5	100.0		
1990	82.1	10.0	0.1	0.1	7.7	100.0		
1995	80.8	10.0	0.1	0.1	9.0	100.0		

Table A-3

TRAVEL BETWEEN CITIES

	Billion Passenger Miles						Thousand Households	Miles per Household
	Automobiles	Airplanes	Buses	Railroads	Waterways	Total		
Actual:								
1969	977	120	25	12	3.8	1138	62073	18333
1970	1026	119	25	11	4.0	1185	63143	18767
1971	1071	120	26	9	4.1	1230	64293	19131
1972	1085	130	26	9	4.2	1254	65464	19156
Estimated:								
1973	1104	135	26	11	4.3	1280	66656	19203
Projected:								
1977	1129	154	37	15	4	1339	71878	18630
1980	1189	172	50	19	4	1434	75847	18910
1985	1323	203	82	25	5	1638	82426	19870
1990	1475	240	92	31	6	1844	88260	20890
1995	1652	281	104	42	6	2085	94970	21950
	As Percent of Total							
Actual:								
1969	85.9	10.5	2.2	1.1	0.3	100.0		
1970	86.6	10.0	2.1	1.0	0.3	100.0		
1971	87.1	9.8	2.1	0.7	0.3	100.0		
1972	86.5	10.4	2.1	0.7	0.3	100.0		
Estimated:								
1973	86.3	10.5	2.0	0.9	0.3	100.0		
Projected:								
1977	84.3	11.5	2.8	1.1	0.3	100.0		
1980	82.9	12.0	3.5	1.3	0.3	100.0		
1985	80.8	12.4	5.0	1.5	0.3	100.0		
1990	80.0	13.0	5.0	1.7	0.3	100.0		
1995	79.2	13.5	5.0	2.0	0.3	100.0		

Table A-4

AUTOMOBILE MILES TRAVELLED

Actual	Between Cities	Within Cities	Total
1969			
Billion Passenger Miles	977	652	1629
Passengers per Automobile	2.487	1.4	-
Billion Automobile Miles	393	466	859
1972			
Billion Passenger Miles	1085	795	1880
Passengers per Automobile	2.489	1.4	-
Billion Automobile Miles	436	568	1004
Projected			
1977			
Billion Passenger Miles	1129	873	2002
Passengers per Automobile	2.5	1.5	-
Billion Automobile Miles	452	582	1034
1980			
Billion Passenger Miles	1189	910	2099
Passengers per Automobile	2.5	1.6	-
Billion Automobile Miles	476	569	1045
1985			
Billion Passenger Miles	1323	969	2292
Passengers per Automobile	2.5	1.6	-
Billion Automobile Miles	529	606	1135
1990			
Billion Passenger Miles	1475	1075	2550
Passengers per Automobile	2.5	1.6	-
Billion Automobile Miles	590	672	1262
1995			
Billion Passenger Miles	1652	1198	2850
Passengers per Automobile	2.5	1.6	-
Billion Automobile Miles	661	749	1410

Note: The automobile occupancy rate of 1.4 persons on trips within cities was determined by a survey made by the Department of Transportation. We expect this rate to increase to 1.6 by 1980 as a consequence of car pooling, stimulated by higher gasoline prices.

Table A-5

NEW AUTOMOBILE REGISTRATION BY SIZE

	Percent New Registrations					
	PADD 5			U.S. Total		
	Small	Intermediate	Large	Small	Intermediate	Large
Actual						
1970	32.6	34.9	32.5	21.8	36.4	41.8
1971	42.4	27.8	29.8	26.0	32.0	42.0
1972	42.7	28.1	29.2	25.9	33.9	40.2
1973	44.4	30.4	25.2	28.2	36.1	35.7
1974 (½ yr.)	47.8	34.0	18.2	30.1	42.4	27.5
Projected						
1975	48	35	17	32	44	24
1976	48	35	17	34	43	23
1977	49	35	16	36	42	22
1978	49	35	16	38	41	21
1979	50	35	15	40	40	20

New registrations have been assumed to hold constant at the 1979 proportions through 1995.

Notes: PADD 5 has led the nation in the swing to small cars, resulting in a decline in the area share of national total gasoline consumption since 1970. We expect the car market to stabilize in future, and with it, the PADD 5 gasoline share.

Table A-6

EFFECT OF AUTOMOBILE WEIGHT AND POWER OPTIONS ON FUEL REQUIREMENT

	Factor
1969 (base year)	1.000
Projections: times 1969 base	
1972	1.037
1977	1.103
1980	1.100
1985	1.113
1990	1.113
1995	1.113

Notes: This factor reflects change in fuel requirement due to the added weight of various safety features (e.g., collision resistent bumpers) and the energy used by power options (mainly air conditioning). The overall factor is influenced by the size of new cars because the fractional effect is greater on a small car than on a large car. Thus an increase in small car registrations tends to increase the factor.

The change indicated above includes the effect of vehicle size, according to the schedule of new automobile registrations given in Table A-5.

Table A-7

EXHAUST EMISSION PENALTY FACTORS

Year of Registration	NO_x at 2 grams/mile*	NO_x at 0.4 grams/mile	Remarks
Base period:			
1969 and before	1.00	1.00	This was the last full year before federal emission regulations took effect.
Times base period:			
1970 to 1974	1.13	1.13	Lower compression ratio
1975 to 1976	1.05	1.05	Catalytic oxidation devices
1977 to 1980	1.10	1.43	Nationwide NO_x controls
1981 to 1985	1.05	1.37	Transmission/aerodynamic changes
1986 to 1990	1.00	1.30	New engines
1991 to 1995	0.95	1.24	Further engine improvements

* Most probable case.

Notes: The penalty factors are the increase over base period fuel requirement caused by engine adjustments to conform to federal automobile emission regulations. The increase applies only to automobiles registered after the initiation date of the regulations. The factors used derive from discussions with U.S. automobile manufacturers and government agencies about actual and anticipated performance.

A limit of 2 grams per mile on NO_x emissions goes into effect in California in 1975. This will increase gasoline usage by about 5 percent and has been taken into account in calculating gasoline demand.

Nationwide NO_x controls at a level of 0.4 grams per mile will go into effect in 1977. This will have a drastic effect on gasoline demand, as shown above. We have, therefore, assumed that the law will be changed to the California standard in calculating the "most probable" future energy demand case.

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Table A-8

EFFECT OF SPEED RESTRICTONS ON
AUTOMOBILE GASOLINE CONSUMPTION

Year	Factor Change Due to Speed Restrictions
1969	1.000
1972	1.000
1977	0.978
1980	0.977
1985	0.977
1990	0.977
1995	0.976

Notes: The nationwide speed limit of 55 miles per hour will increase average miles per gallon for automobile journeys between cities but will not affect fuel usage within cities. The best current information is that the average fuel saving will be about 5 percent if all drivers slow down from the previous average speed of 62 miles per hour to an average of 55 miles per hour. If the average speed is less than 55 miles per hour, a greater fuel saving will be realized.

The above calculations assume a 5 percent saving on journeys between cities. The factor declines because driving between cities is expected to gain slightly within total driving.

The change is relative to fuel usage without the speed restrictions, NOT to 1969 average fuel use as in the case of the emission control penalty factors.

Interstate Commerce Commission
Washington, D.C. 20423

OFFICE OF THE CHAIRMAN

September 13, 1976

SEP 14 19

Honorable Henry M. Jackson
United States Senate
Washington, DC 20510

Dear Senator Jackson:

This is in response to your letter of August 23, 1976, and the attached questionnaire submitted jointly by the Committees on Interior and Insular Affairs and Commerce. Your inquiry concerns an anticipated crude oil surplus on the West Coast when the Trans Alaska Pipeline begins operations.

While this Commission and its members are vitally concerned about the Nation's petroleum supply problems, its statutory authority for dealing with them is quite limited. Our responsibility is limited to an economic form of regulation and all common carrier pipelines devoted to the transportation of crude oil and refined petroleum products. The regulatory efforts required for pipelines have not been large compared to those required for other transportation modes regulated by the Commission. Congress has devised a much less comprehensive range of regulatory devices for this industry.

Oil pipelines are not required to obtain certificates of public convenience and necessity from the Commission before they can begin operating. The Interstate Commerce Act does not give us jurisdiction over such aspects of pipeline operation as planning, financing, construction, or abandonment of lines. Our jurisdiction is limited to assuring just and reasonable rates; forbidding undue preference, prejudice, and discrimination in rates and service; requiring reasonable facilities for the interchange of traffic; and requiring compliance with the long and short haul provisions of section 4 of the Interstate Commerce Act and with the requirement to provide and furnish transportation upon reasonable request. In this regard, pipeline common carriers must comply with the Commission's tariff, accounting, reporting, and valuation regulations. A more comprehensive outline of this Commission's statutory authorities and responsibilities is included in Appendix A.

While the Commission officially has no special knowledge or responsibility concerning the various proposals for dealing with surplus crude oil on the West Coast, our staff has been monitoring the overall situation. In line with your request, we have responded to questions IV and V in Appendix B.

If I can be of further assistance to you in this or any other matter, please do not hesitate to call upon me.

Sincerely yours,

George M. Stafford
Chairman

Enclosures

Commissioner MacFarland was absent and did not participate.

APPENDIX A

BACKGROUND ON PIPELINE REGULATION

Regulation of oil pipelines was brought under the Commission's jurisdiction by amendment of the Interstate Commerce Act of June 29, 1906. Generally the Commission's jurisdiction over pipelines extends primarily to the following matters, which are set forth in Title 49 of the United States Code:

The pipelines' duty "... to provide and furnish transportation upon reasonable request therefor..." [Section 1(4)] and "... to establish reasonable through routes with other such carriers..." [Sections 1(4) and 15(3)] and establish "... just and reasonable rates, fares, charges and classifications..." [Sections 1(4) (5) and (6)]

The prohibition against subjecting any shipper, locality or territory ... to any undue or unreasonable prejudice or disadvantage in any respect whatsoever..." [Section (3)]

The prohibition against charging or receiving "any greater compensation in the aggregate for the transportation... of like kind of property for a shorter than for a longer distance over the same line or route in the same direction, the shorter being included within the longer, or to charge any greater compensation as a through rate than the aggregate of the intermediate rates..." [Section 4]

The requirement that every pipeline file with the Commission all rates, charges, classifications, regulations and practices for transportation between all points on its system [Section 6] and not demand or collect any different compensation for transportation than specified in its filed tariff [Sections 2 and 6(7)]

The authority of the Commission to review all pipeline rates and, if it determines that a rate is unjust or unreasonable, or unjustly discriminatory or unduly preferential, to suspend such rate and determine the just and reasonable rate [Sections 15(1) and (7)]

The prohibition against a pipeline's entering into any agreement with any other pipeline for the pooling or division of traffic service, or gross or net earnings, except upon the specific approval by order of the Commission [Section 5(1)]

Agreement between or among pipeline companies regarding rates, charges, and classifications [Section 5a]

The duty of every pipeline to file annual, periodical, and special reports as the Commission may require and in the form so required [Section 20(1)]

The authority of the Commission to prescribe a Uniform System of Accounts for pipelines which shall be used by all pipelines [Section 20(3)] and to prescribe rates of depreciation for pipeline property which must be used by all pipelines [Section 20(4)]

The authority of the Commission or any duly authorized special agent, accountant or examiner at all times to inspect all accounts, books, records, correspondence or other documents of every pipeline [Section 20(5)]

To provide a basic and annual valuation of each pipeline's property [Section 19a]

Violations of the Clayton Antitrust Act [15 U.S.C. 12 et seq.]

On the other hand the Commission has no jurisdiction over the following matters:

The pipeline's facilities for operating [Section 1(4)]

The construction or abandonment of lines [Section 1(18)]

The issuance of securities [Section 20a]

The formation of interlocking directorates [Section 20a(12)]

The merger or consolidation with another pipeline [Section 5]

The commodity clause which prohibits the transportation of property by its owners [Section 1(8)]

APPENDIX B

ANSWERS IN RESPONSE TO QUESTIONNAIRE ON POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

Question: IV B. If you have knowledge of these proposals (set forth in IV A), evaluate and compare the foregoing responses and any other relevant alternatives with respect to:

1. The current status of each project or proposal;

2. The estimated time for approval and implementation including a description of:

   (a) any required Federal regulatory proceedings, approvals, leases or permits;

   (b) any required State regulatory proceedings, approvals, leases or permits;

   (c) any required regulatory proceedings, approvals leases or permits which must be processed in other countries;

   (d) any treaty requirements; and

   (e) construction schedules, including if necessary tanker construction schedules.

3. Direct capital and operating costs;

4. Financing arrangements;

5. Refiner and consumer costs of crude oil nationally or by region;

6. Wellhead price for North Slope crude oil, cash flow to the operating companies, and revenues to the State of Alaska;

7. Net overall national economic costs and/or benefit;

8. Promotion of the capacity for long-term domestic self-sufficiency;

9. Environmental and safety impacts; and

10. Any other relevant factors.

Answer: Due to the fact that the Commission does not have certification authority for proposed construction of new pipelines or tanker operations, we have no special knowledge of the alternatives for transporting crude oil from Alaska. We are, however, interested in assuring the availability of adequate and efficient facilities for transporting any excess crude to points where it is needed and can be effectively utilized.

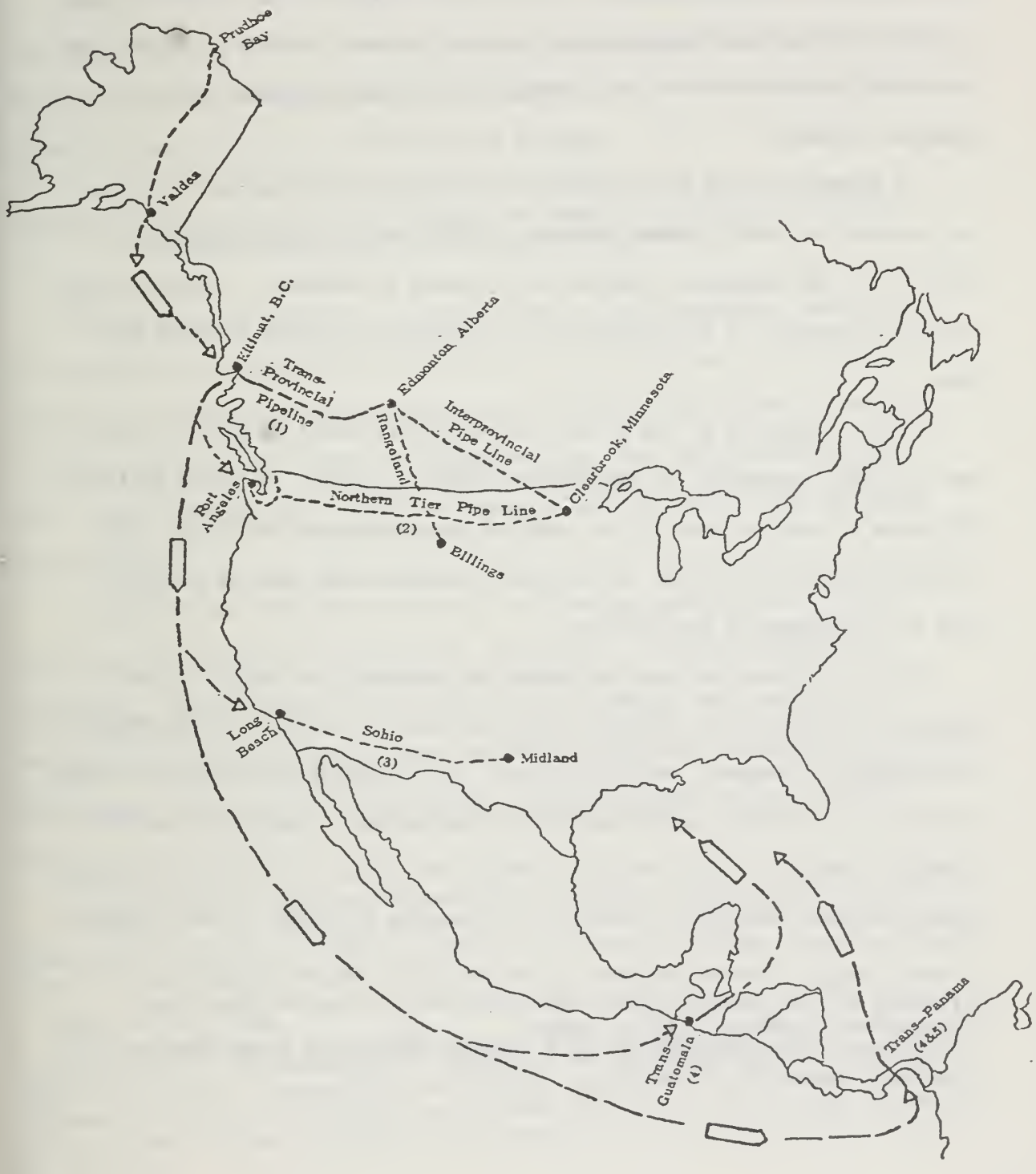
While our jurisdiction over the several proposals outlined in Part IV A is minimal until a pipeline is ready to begin operation within the United States, we make every effort to keep abreast of significant activities and developments because of their potential impact on regulated activity. Our comments will be confined to those proposals about which we have gained some insight from reliable interviews, published material, and other sources. Generally, this will include proposals 1 through 5 with additional comments regarding the feasibility of utilizing unit tank trains to transport crude from West to East. A map of proposals 1 through 5 is presented on page 3.

Proposal 1 - Construction of the Proposed Trans-Provincial Pipeline from Kitimat, British Columbia, Connecting with Interprovincial Pipe Line at Edmonton, Alberta.

The 12 sponsors of this alternative[1] have recently concluded, on the basis of a joint feasibility study, that construction of this pipeline is

[1]Amoco Oil Co., Ashland Oil, Inc., Continental Oil Co., Farmers Union Central Exchange, Husky Oil Ltd., Koch Industries, Marathon Pipeline Co., Murphy Oil Corp., Hudson Bay Oil and Gas Co., Interprovincial Pipe Line Ltd., Total Leonard, Inc., and Trans Mountain Oil Pipe Line Corp.

PROPOSALS 1 TO 5 AS DESCRIBED BY COMMITTEES' QUESTIONNAIRE



a viable project and have applied to the Canadian National Energy Board (NEB) for the necessary permits. The proposal calls for the construction of a marine terminal near the deepwater port of Kitimat, British Columbia, and laying 800 miles of 30-inch line between Kitimat and existing lines at Edmonton, Alberta.

At Edmonton, crude would enter the Interprovincial/Lakehead Pipe Line for movement to North Dakota, Minnesota, Wisconsin, and the Great Lakes Region, and the Rangeland Pipeline for movement to Montana. Canadian crude oil would continue to be transported to Vancouver via Trans Mountain Pipe Line.

Initial capacity of the Trans-Provincial line would be 300,000 barrels per day (BPD) expandable to 500,000 BPD within 6 years.[2] It would utilize 300 miles of right-of-way of the existing Trans Mountain Pipe Line. The estimated capital costs for the terminal, pipeline, and pumping stations will be approximately $400 million.[3]

No U.S. permits are required since the proposed line would be constructed entirely within Canada. The consortium has applied to the NEB for certification. However, public hearings, as required by the National Energy Board Act, could delay processing of the application. Approval is anticipated in late 1977. The estimated construction time for the entire system (dock, terminal facilities, pipeline, and pumping stations) is one calendar

[2]Crude Supply Alternatives For the Northern Tier States, Volume II (Prepared for the Federal Energy Administration by Bonn and Moore Associates, Inc., July 25, 1976) p. 4-37.

[3]Telephone interview with Mr. G. A. Irving, Secretary, Trans Mountain Pipe Line, August 30, 1976.

year from the date of certification.[4]

Although financing arrangements have not been finalized, it is probable that debt financing will be divided among the parties based upon their level of participation. Similar financing arrangements were used by the oil companies in the construction of the Alaskan pipeline.

Proposal 2 - Construction of the Proposed Northern Tier Pipeline from Port Angeles, Washington to Clearbrook, Minnesota.

The Northern Tier Pipeline (NTP) project[5] would require the construction of a tanker unloading facility and storage site at Port Angeles, Washington. This site was chosen because it would not be affected by the State law which prohibits tankers larger than 125,000 deadweight tons (dwt) from entering upper Puget Sound and it provides an adequate depth of water to accommodate larger tankers.

A large 36-inch diameter pipeline would extend approximately 1,500 miles from Port Angeles to Clearbrook, Minnesota. The line would cross Washington, Idaho, Montana, North Dakota, and Minnesota and connect at specified points with existing lines to serve refineries in the Rocky Mountain, Mid-Central, Midwest, and Eastern States. Railroad rights-of-way will be used wherever practical.

Pipeline officials have indicated that they will cooperate with Northern Puget Sound refineries if they desire to lay a line to connect with the NTP.

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[4] Ibid, G. A. Irving.

[5] The participants in this proposal are Butler Associates, Curran Oil Co., Glacier Park Co. (a subsidiary of Burlington Northern), MAPCO, Inc., Milwaukee Land Co. (a subsidiary of Chicago, Milwaukee, St. Paul and Pacific Railroad), Patrick J. McDonough, and Western Crude Oil. None of the sponsors own any Alaskan crude or have a major interest in the refineries to be served by the line.

The design capacity of the NTP will be 1.3 million BPD between Port Angeles and North Bend, Washington, where provisions will be made to pump 500,000 BPD to the Puget Sound refineries. The capacity from North Bend to Clearbrook will be 400,000 BPD initially and later expanded to 800,000 BPD.

It will take approximately 2 years to complete the NTP after the necessary permits and approvals have been granted. An additional 2 years may be necessary to obtain the required permits and environmental impact statements. NTP has already filed with Washington State for the construction of the Port Angeles terminal and storage facilities, and the 450 miles of pipeline extending to the Washington-Idaho border. According to D. Michael Curran, Northern Tier president, the firm plans to begin construction on the tanker terminal in May 1977, completing the terminal and line by 1979.

Unlike previously constructed crude lines, NTP will not seek throughput agreements with oil companies or refineries in order to acquire financing for the project. The estimated cost to construct the line and its related facilities is $1.0 billion.

Proposal 3 - The Proposed Sohio Project to Convert and Reverse the Existing El Paso Natural Gas Pipeline and Build Necessary Connecting Pipelines from Long Beach, California, to Midland, Texas.

This proposed project has progressed to the point of applying for right-of-way permits from the Department of Interior and leasing an additional segment of already completed pipeline. The newly leased segment is 125 miles of 30-inch line extending from the California-Arizona border to Moreno, California, and is presently in gas service, belonging to the Southern California Gas Company. The entire project is dependent upon decertification,

by the Federal Power Commission, of the 30-inch, 700-mile El Paso Natural Gas line, which has not yet been granted. Hearings began in July of 1976. Meanwhile Sohio has run into difficulties with the Environmental Protection Agency (EPA) and the California Air Resources Board (CARB) over its planned 9 million barrels of tank storage in the Los Angeles Basin, which it must have to receive the Alaskan crude and operate the pipeline. EPA has said that emissions in the Basin, such as would occur from crude oil storage tanks, cannot be increased. The tentative early 1978 completion date is based upon completion of a Federal environmental impact statement and EPA and CARB approval by the first quarter of 1977, and the beginning of construction on harbor facilities at Long Beach, and on the 42-inch line between Long Beach and Moreno, by the second quarter of 1977.

Estimated cost of the project is $500 million, including port and terminal facilities, rights of way, and interest. It is anticipated that the capacity of the line will be 500,000 barrels per day.[6] Financing arrangements are still very tentative. Presently, Sohio has not been approached by other companies interested in the project. It is anticipated, however, that others with similar interest in transporting crude oil from the West Coast to the Mid-Continent area will participate in this proposal.

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[6]Telephone interview with Mr. Frank Garibaldi, President, Sohio Transportation Co., August 30, 1976.

Proposal 4 - Construction of a Pipeline Across the Isthmus of Panama or Across Guatemala to Connect Tanker Route from Alaska with Tanker Route to the U.S. Gulf Coast.

We are not aware of the present status of these alternatives. The Navy does control an existing pipeline across the Isthmus of Panama although it is presently not in use. According to a spokesman from the Association of Oil Pipelines, there is an agreement with Panama whereby the U.S. will not implement any mode of transport which would compete with the Canal.[7]

Proposal 5 - Use of Small Tankers Through the Panama Canal or Very Large Crude Carriers (VLCC's) Around Cape Horn to the U.S. Gulf Coast.

Tankers of 58,000 to 60,000 dwt could transit the Panama Canal fully loaded, and those up to 90,000 dwt could be used to carry partial loads.[8] A detailed analysis would have to be made of the cost trade-offs between utilizing the Canal versus using Very Large Crude Carriers (VLCC) (over 200,000 dwt) around Cape Horn. Another alternative would be to use VLCCs to offload to smaller tankers at the Canal to complete the movement.

Section 27(b) of the Alaskan Statehood Act preserved the jurisdiction of the Federal Maritime Commission over water transportation on the high seas between ports in Alaska and ports in the other 48 States.

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[7]Telephone interview with Mr. Donald G. Riley, Association of Oil Pipelines, September 7, 1976.

[8]Howard M. Wilson. "Beefed-Up Tanker Fleets Readied for N. Slope Oil," The Oil and Gas Journal, June 14, 1976. p. 24.

Additional Proposal - Use of Unit Train Tank Cars for Movement Inland from the West Coast.

While not mentioned in the questionnaire, we believe that serious consideration should also be given to the use of unit train tank cars. Recent innovations in tank car technology may make them competitive with pipelines in certain situations. TANK TRAIN, a proprietary product of General American Transportation Corporation (GATX), is a system of interconnected tank cars which allows the loading and unloading of a string of cars from one connection at flow rates up to 3,000 gallons per minute. A 90-car TANK TRAIN unit train of 23,150 gallon tank cars in five 18-car strings, can load or unload 49,607 barrels in less than 6 hours. According to Mr. Marcus S. Kostolich of GATX, TANK TRAIN can compete with pipelines of capacities up to 350,000 BPD. Each individual situation, of course, must be fully studied before any determination of competitiveness at any volume can be determined.

GATX is the largest manufacturer and lessor of tank cars in the world and has a tank car fleet in the U.S. exceeding 53,000 cars. It also has the largest coal car lease fleet in operation in the Nation, having nearly 1,000 cars in operation. The TANK TRAIN concept was field tested for 2 years before being offered commercially in late 1975. Last spring, the first commercially operated TANK TRAIN cars began distributing #6 fuel oil to customers for Cirillo Brothers Petroleum Products Company.[9]

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[9] Letter, dated June 9, 1977, subject: Tank Trains for the Northern Tier Refineries, from M. S. Kostolich of GATX to Dr. W. P. Allman, Office of Transportation Economics Analysis, U.S. Department of Transportation.

While the TANK TRAIN is an innovation, large volume rail transportation of crude oil by tank car is not. During World War II the vast bulk of crude oil was transported by rail tank cars. This was a necessity with the diversion of tankers to war duty and the German submarine threat.[10] Since 1974, the Southern Pacific Railroad has operated four 70-car unit trains for Standard Oil of California from Salt Lake City to its refinery in Richmond, California--a distance of 800 miles. Each unit train carries 37,000 barrels of crude oil. The conventional 23,000-gallon tank cars are leased from Union Tank Car Company. The operation has been highly successful.[11] We might also point out that movement of liquid commodities by tank car or truck from the termini of pipeline or other facilities is a possibility which should not be discounted.

Important advantages of the TANK TRAIN concept include:

1. Faster loading and unloading than conventional tank cars.
2. Lower costs made possible by unit train operation.
3. The potential, under proper supply and demand situations, to triangulate and back haul compatible liquids and slurries.
4. The generation of additional traffic and revenues for the Nation's rail system.
5. Lower investment requirements than alternative pipeline proposals.
6. A greater flexibility in supplying refineries than pipelines in response to any sudden change in crude oil sources caused by embargoes of imported oil or other changes in distribution patterns.

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[10] Interstate Commerce Commission, Bureau of Transport Economics and Statistics. War-Built Pipe Lines and the Post-War Transportation of Petroleum. Statement No. 4432. (Washington, D.C., ICC, August 1944), pp. 43-65.

[11] "70-Car Unit Trains Keep Crude Oil Flowing," Railway Age, September 9, 1974, p. 38.

GATX has prepared estimates of the feasibility and costs of transporting Alaskan crude oil by TANK TRAIN over both Northern Tier and California-Texas routes. Major railroads serving the Northern Tier from the Puget Sound area are the Burlington Northern (BN), Chicago, Milwaukee, St. Paul & Pacific (MILW), and the Union Pacific (UP) Railroads. Only the BN and the MILW have routes through the Northwest to Chicago. Northern Tier refinery destinations to which GATX estimated costs were St. Paul, MN, Billings, MT, Bismarck, ND, Superior, WS, Laurel, MT, and Wrenshall, MN. GATX concluded that if TANK TRAIN were used to supply directly the refineries at a volume of 460,000 BPD, 5,994 TANK TRAIN cars would be needed and could be leased at a cost of $34,417,548 per year. If TANK TRAIN cars were used to supply pipelines serving refineries, the requirement would be 4,768 cars leased for $27,377,856 per year. The BN has told GATX it would probably file a tariff of $2.80 per barrel to transport crude oil direct from Puget Sound to St. Paul. This tariff would not include tank car rental, switching charges, the cost of a Pacific Coast terminal, nor the costs of loading and unloading TANK TRAIN. GATX claims it will have the capability to produce 2,000 TANK TRAIN cars in 1977. At the end of the West Coast surplus condition, the TANK TRAIN cars could be sold or leased to other railroads or operators.[12]

In the California-Texas TANK TRAIN proposal, GATX examined the movement of Alaskan crude oil from the Long Beach area to Midland for volumes up to

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[12]Letter, dated June 9, 1976. GATX to DOT. pp. 8-15.

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150,000 BPD. Railroads that could participate in such a movement include the Atchison, Topeka, and Santa Fe Railway (ATSF), the Missouri Pacific Railroad (MOPAC), and the Southern Pacific Transportation Company (SP). The ATSF and the SP both advised GATX that due to heavy traffic congestion at Long Beach there is a 100,000 BPD limit for the amount of crude oil that could be transported out of the Long Beach port area. This could be averted, however, if cars were loaded at points east of Long Beach such as Corona Colton or Indio. Corona is about 40 miles east of Long Beach and if it were used 2,079 TANK TRAIN cars would be required to move 150,000 BPD to the Sweetwater/Midland, Texas, area. Annual lease rates for each TANK TRAIN car would be about $5,760. GATX estimated annual operating costs for this movement would be $444,364.[13]

Question: IV C. Implementation

1. (a) Considering the foregoing factors which of the alternatives or combination of them currently appears on balance to be best?

   (b) Which appear to be workable and acceptable?

   (c) Unworkable or unacceptable? (Why)?

2. (a) Among those alternatives identified as workable and acceptable, which are now under active consideration by producers, refiners, or others?

   (b) Which have reached the stage of applications for necessary certificates, licenses, or permits?

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[13]GATX, "Tank Train Proposal to the Atlantic Richfield Company," February 26, 1976.

3. For each of those alternatives identified as workable or acceptable, what appear to be most significant critical hurdles to implementation (for example, demonstration of technical or economic feasibility; Federal or State air quality standards; obtaining competent and credible corporate sponsors; throughput commitment; legal authority; financing; Federal approval of required certificates, licenses, or permits; foreign country, State, or provincial approvals or certificates, licenses or permits).

4. For each of those alternatives identified in IV A, what is your understanding of the time frame for completion? At what capacity?

Answer: A definitive appraisal of the acceptability and/or workability of the various proposals is beyond the scope of our activities and statutory responsibilities. However, based upon our analysis, of the very limited information available to us we have briefly summarized below the advantages and disadvantages of each.

Proposal 1 - Trans-Provincial Pipeline.

- This proposal is supported by a consortium of 12 owners that is comprised of Northern Tier refiners, major oil companies, and existent Canadian and U.S. pipelines. Many of the owners will be users and suppliers of the surplus crude which gives this proposal considerable impetus.

- It will utilize already existent pipelines which presently have excess capacity, help alleviate the surplus of West Coast crude and the deficient crude supply facing the Northern Tier refiners. Additionally, the connecting Interprovincial Pipe Line can easily be expanded to handle larger volumes.

- The projected cost, $400 million, of this proposal is less than either the Sohio or Northern Tier lines.

- Currently there appears to be less environmental opposition to port facilities at Kitimat than at Long Beach or Port Angeles.

- Certification of this line is simplified somewhat by the fact that the Canadian NEB has the authority to grant both the certificates of public convenience and necessity, and the right of eminent domain.

- This line will not be subject to Commission review or control of tariffs and rates even though it will be transporting U.S. crude to U.S. markets. Also, the line will be subject to controls completely outside U.S. jurisdiction.

Proposal 2 - Northern Tier Pipeline

- This line will be located wholly within the U.S. and thus not subject to foreign controls of any type.

- It has more potential capability for supplying the numerous refineries in the Puget Sound area as well as those in the Rocky Mountain and Dakota areas. Some of these would not be serviceable by the Trans-Provincial Pipeline. NTP will be capable of serving virtually every refinery contemplated by the Trans-Provincial line.

- The investment will be in the U.S. economy.

- It does not have the support at this time of any of the Northern Tier refiners or the suppliers and/or purchasers of Alaskan or other crude.

- The project is expected to require $1.0 billion in capital investment. In addition, the design capacity of the line appears to be in excess of that required by Northern Tier refineries.

- Financing could be difficult without throughput and deficiency agreements from shippers or purchasers. The high capital requirements could also be detrimental to financing.

- The estimated construction time of 2 years plus anticipated delays due to environmental opposition and State and local authorizations seems to indicate that the project completion date of September 1979 may be unduly optimistic.

Proposal 3 - Sohio Pipeline Project.

- This proposal will take advantage of excess capacity existing in the El Paso and Southern California gas systems, and will require considerably less new line construction than either the Trans-Provincial or Northern Tier Pipelines. If there should continue to be a decline in the supply of natural gas, additional lines could be converted to provide greater capacity for crude. On the other hand these excess lines may possibly be required for Alaskan gas should it be liquefied and transported by tanker to the West Coast.

- The capital investment required, estimated at $500 million, would be comparable to that required for the Trans-Provincial Pipeline.

- By utilizing excess capacity of existing lines which connect at Midland, Texas, the Sohio project has the capability of supplying crude to refineries in the Gulf Coast, Southwest, and Mid-West regions.

- Adequate long term throughput for the line is assured since Sohio owns a majority of both the Alaskan crude reserves and the Trans Alaska Pipeline System (TAPS).

- The projected completion date is earlier than the other proposals by 1 to 2 years, however, the project is dependent upon Federal Power Commission (FPC) decertification and the solving of environmental problems in the Los Angeles Basin. Sohio has recently run into environmental difficulties with both the Environmental Protection Agency and the California Air Resources Board in that there can be no more emissions in the Basin.

Proposal 4 - Pipeline Across Panama or Guatemala.

- Due to limited information regarding this proposal, we do not feel qualified to comment on its feasibility. It would appear, however, that negotiations of requisite international agreements, the time

required for construction, and national security considerations would be limiting factors.

Proposal 5 - Tankers Through Panama Canal or Around Cape Horn.

- Although we lack sufficient information for a thorough analysis of this proposal, use of tankers would seem to be a viable short run alternative. Detailed study of the relative total costs involved and time required for small tankers transiting the canal or VLCCs around Cape Horn would be necessary to determine the most economical alternatives.

Additional Proposal - Unit Train Tank Cars.

- Utilization of unit train tank cars would require a much lower initial capital investment than pipeline proposals; however, it is also probable that operating costs will be higher.

- TANK TRAIN would be a relatively low risk, high flexibility alternative. Existing rail lines could be used to transport crude oil or other commodities to a variety of localities as changes in supply and/or demand patterns arise.

- The additional traffic generated would be a boon to many U.S. railroads faced with fixed plant facilities and excess capacity.

- According to GATX, on a total cost basis, TANK TRAIN would be competitive with pipelines only up to 350,000 BPD.

- Under proper supply and demand situations, backhaul of compatible liquids and slurries could be arranged.

- Over time, railroad operating costs may be more vulnerable to inflation than pipelines.

- The tank car lessor, GATX, will probably want some guarantee of a long-term commitment before it would manufacture tank cars on a large scale.

Conclusion

Central to the evaluation of the various proposals for dealing with this problem is an overall public policy objective. We believe this objective should be to minimize, to the greatest extent possible, any disruption of existing United States crude oil distribution patterns and petroleum industry capital requirements. This is particularly important given the uncertain nature of the projected West Coast surplus and the expanding capital requirements for nontransportation phases of the petroleum industry. With this overall objective in mind, the various proposals could be judged as to their acceptability. Any such evaluation should be based on a comprehensive analysis of all relevant information.

Given the very limited information available to us and our lack of regulatory jurisdiction in the area, it would be presumptuous for us to state a preference for any particular proposal at this time. We would be pleased, however, to supplement this statement in the future in the light of ongoing developments to help assure that the Congressional examination of the various policy issues involved may be as complete as possible.

Question: IV D. Federal Policy Role

1. If none of the pipeline systems listed in IV A 1-3 (Kitimat, Northern Tier, and Sohio) is approved and constructed in time to transport any of the anticipated West Coast surplus in PADD V created by North Slope crude oil production, how would you recommend the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV A 4-9.)

Answer: As noted elsewhere in this reply, the Commission's specific knowledge and jurisdiction regarding pipelines deals essentially with rate regulation. Our comments set forth in this paragraph should be taken as those of an informed observer rather than as those of an economic regulator with subject matter jurisdiction. From an economic standpoint, exchanges of crude oil with third nations on a short term basis would appear to be preferable to the shutting-in of producing capacity in Alaska. The Nation's balance of payments would be negatively affected by allowing shut-in capacity since the production loss would have to be offset by purchased imports. Also, delays in recoupment of capital by TAPS owners would ultimately result in higher costs to the consumer. Exchanges on a long term basis (pending increases in West Coast crude oil demand to absorb the surplus) may still be desirable economically, as the surplus absorption on the West Coast may occur before the economic payout of expensive pipeline systems. However, such exchanges would not lessen U.S. dependence upon foreign crude. If Alaskan reserves are exchanged, then an embargo could still leave us with an energy shortage since we would be without the necessary or optimum transportation and refining facilities to utilize Alaskan crude.

The choice between retrofitting existing Northern Tier and West Coast refineries or desulphurizing the crude before transshipment to the existing refineries appears to be primarily an economic consideration for the individual petroleum companies involved.

Question IV D 2. What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?

Answer: The Commission has neither the expertise nor the information to make a knowledgeable recommendation.

Question: IV D. 3 (a) Is there a need for Federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PADD V?

(b) What, if any, constraints should such legislation address?

Answer: The Commission does not presently seek additional authority over the pipeline industry--believing that our existing authority is adequate and that the question of increased regulation is a matter that the Congress itself must determine. Nevertheless, if Congress does decide to expand Federal economic regulation in the area of oil transportation for any purpose, such expansion should fall within the regulatory framework of the Commission, so that the Commission can provide uniform and coordinated regulation of all surface common carriers and maintain an adequate integrated transportation system. If additiona economic regulation of pipelines is deemed necessary and placed in a department

of the executive branch, on which the congressional directive of the National Transportation Policy is not binding, then congressional stewardship will be lost. The problems of dual regulation will best be avoided by vesting any additional regulatory authority the Congress believes necessary with the Commission.

Question: V A. What is the full anticipated cost of constructing and equipping the Trans Alaska Pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?

Answer: As the Trans Alaska Pipeline will automatically become a common carrier due to its involvement with Federal lands, our valuation staff has been actively engaged in monitoring the pipeline's construction and costs, and in preliminary valuation work. The cost projections being made at this time by the owners, for the pipeline and its terminal facilities, are for the daily capacity of 1.2 million barrels. The currently projected cost for the facilities alone is $7.7 billion. However, the cost projections have been constantly escalated since inception. Including interest and other overhead expenditures related to construction, and further escalation based on past experience, it is anticipated that this pipeline will ultimately cost about $9.5 billion at the capacity of 1.2 million BPD. Without further escalation in cost estimates it will cost about $9.0 billion.

To bring the pipeline to a capacity of 2.0 million BPD will require additional reception facilities at Prudhoe Bay, four additional pumping stations, additional pumping units at each of the existent eight stations, approximately 14 additional storage tanks and a tanker berth at the Valdez terminal, plus additional control and miscellaneous facilities. The estimated

additional cost to attain a pumping capacity of 2.0 million BPD is $750 million. The total cost at this capacity would thus be approximately $9.75 to $10.25 billion.

Question: V B. What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985. (Specify throughput assumptions?) What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?

C. To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act, or (b) at the upper tier price established by FEA, be expected to constrain West Coast refinery prices? Refinery prices east of the Rockies?

D. If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g., imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?

E. To what extent, if at all, would the alternative measures identified in question IV A affect average prices of North Slope and similar grade crude oil produced in PADD V (a) at the wellhead, (b) at WestCoast refineries, and (c) at refineries east of the Rockies?

Answer: For the Commission to present any estimates of TAPS crude oil tariffs would greatly prejudice any future proceedings the Commission might have concerning the reasonableness of such rates. This would be unfair to both the participating TAPS carriers and the individuals who might protest a proposed rate in proceedings before this Commission. The Attorney General of Alaska has already indicated that the State will probably protest initial TAPS rates.[14]

[14] "State Hires Law Firm," Anchorage Times, July 3, 1976.

An estimate of $4.50 per barrel was mentioned as "the best estimate made so far" in a recent issue of The Oil and Gas Journal. Tanker rates were also estimated to range from $.50/bbl. to $1.00/bbl.[15]

We believe that parts C, D, and E of question V fall largely outside of our domain. We defer, therefore, to other agencies which would be better qualified to comment on these aspects of this situation.

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[15]Howard M. Wilson. "Beefed-Up Tanker Fleets Readied for N. Slope Oil," The Oil and Gas Journal, June 14, 1976, p. 24.

UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Maritime Affairs
Washington, D.C. 20230

SEP 15 1976

SEP 17 1976

Honorable Henry M. Jackson
United States Senate
Washington, D.C. 20510

Dear Senator Jackson:

This is in response to your letter of August 23, 1976, requesting a response to your questionnaire on the trans-Alaska pipeline. As you know the Federal Energy Administration is in the final stages of a comprehensive study dealing with this entire subject matter.

For several months MarAd has worked very closely with FEA in the preparation of this study which was originally requested by the ERC. The Maritime Administration's input has dealt primarily with marine transportation including: the use of Panamax tankers through the Canal or VLCC's around Cape Horn to the U.S. Gulf Coast; U.S.-flag tanker construction schedules; the employment of U.S. tankers to transport Alaskan crude oil; tanker costs; and the availability of U.S.-flag tankers under OPEC or OAPEC embargo conditions.

We understand that a draft of FEA's report encompassing these and other energy issues is expected to be available for your review by the end of September.

I share your concern about the resolution of these issues and can assure you of the Maritime Administration's cooperation.

Sincerely,

for Howard Casey

ROBERT J. BLACKWELL
Assistant Secretary
for Maritime Affairs

DEPARTMENT OF THE ARMY
OFFICE OF THE CHIEF OF ENGINEERS
WASHINGTON, D.C. 20314

REPLY TO
ATTENTION OF:

DAEN-CWR-L

14 SEP 1976

Honorable Adlai E. Stevenson
United States Senate
Washington, D. C. 20510

Dear Senator Stevenson:

I am pleased to respond to your 23 August 1976 letter, addressed to Lieutenant General J. W. Morris, Chief of Engineers, which Senators Magnuson and Jackson cosigned.

The U. S. Army Corps of Engineers is not in a position to offer detailed information or much insight into the questions broached in Part IV. They generally encompass matters within the jurisdiction of other Federal agencies. With respect to IV.A.2, however, we are generally aware of the nature of the proposal to construct a Northern Tier pipeline from Port Angeles, Washington to Clearbrook, Minnesota. Project adherents recently briefed BG Drake Wilson, Deputy Director of Civil Works, and staff on their proposed pipeline project. No lead Federal agency has been designated for preparation of an Environmental Impact Statement (EIS). Any necessary coordination on matters impinging on our Civil Works responsibilities would, in any event, devolve on the Seattle District Engineer, since the Port Angeles facilities would be located within his geographical jurisdiction. I would like to emphasize that there has been no significant activity to date involving the Corps of Engineers.

Our Los Angeles District Engineer is working closely with the Bureau of Land Management project office, Los Alamitos, California, on the proposed SOHIO project (IV.A.3). The Los Angeles District is providing certain inputs to the Department of the Interior, which is the designated lead agency on the EIS. The Corps is providing information on harbor modifications at Long Beach, submerged crossings of navigable waters, and effects on flood control right-of-way in Southern California. In addition, we are functioning as contract manager on sea-leg aspects.

I am sending a similar letter to Senators Magnuson and Jackson. Since a number of other agencies are also responding to the questionnaire, I am providing a copy of my response to the Office of Management and Budget.

DAEN-CWR-L
Honorable Adlai E. Stevenson

I hope that this information will prove sufficient for your immediate needs. If you have any further questions, please let me know.

Sincerely,

V. L. RATHBURN
Colonel, Corps of Engineers
Assistant Director of Civil Works,
Pacific

DEPARTMENT OF THE ARMY
OFFICE OF THE CHIEF OF ENGINEERS
WASHINGTON, D.C. 20314

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Assistant Director of Civil Works,
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JAY S. HAMMOND
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

September 16, 1976

The Honorable Henry M. Jackson
The Honorable Warren G. Magnuson
The Honorable Adlai E. Stevenson
United States Senate
Washington, D. C. 20510

Dear Senators Jackson, Magnuson and Stevenson:

Thank you for your joint letter of August 23 inviting my comments about crude oil production from Alaska's North Slope and the crude oil "surplus" that is likely to develop in PADD V after Prudhoe Bay comes on stream. I especially welcome this opportunity to address these subjects because all of the Prudhoe Bay oil field as well as the known offshore fields in Cook Inlet lie entirely on State lands and constitute -- to a degree unique in the United States -- a public asset, owned by the People of Alaska. We are relying heavily on these oil and gas resources, and consequently the matter of a West Coast oil "surplus" and its possible effects on us are of vital interest to all Alaskans.

Apparently to assist us in focusing on the major facets involved in responding to your inquiry, you enclosed a comprehensive questionnaire with your letter. I have directed the appropriate State agencies to address themselves to it, and upon their responses is based much of what follows. Unfortunately it has not been possible to prepare a detailed answer to every single one of the particular questions -- either because information needed to answer some questions is not available or because the analysis required to answer them simply could not have been completed in time. However, we have been able to answer most of the questions.

Crude oil supply from Alaska. Our current best estimate of the start of North Slope production is that the Prudhoe Bay field will have been readied to produce at 600,000 barrels a day before mid-1977. Shortly after mid-1977 the field production capacity will increase to 1,200,000 barrels a day. The constraining factor on the begining of North Slope oil deliveries will not be the readiness

of the field to produce the oil, but the readiness of the Trans Alaska Pipeline System (TAPS) to transport it. The present welding problems with the pipeline are not expected at this time to result in a delay in its completion, provided that Alyeska is promptly notified of the remedial work that it may be required to make by the Departments of Transportation and Interior, so that it has time to be physically able to get the work done within its announced timetable. Delays in these requlatory agencies are beyond Alyeska's power to do anything about, but as long as the problems are solvable by liberal doses of manpower and money TAPS should come on stream as scheduled -- 600,000 barrels a day in mid-1977 and 1,200,000 barrels a day before the end of the year. No other difficulties in just throughput are expected, but "start-up" problems cannot be completely ruled out.

The timing of an expansion of TAPS capacity beyond 1,200,000 barrels a day is more difficult to predict. The agreement among the owner companies to form the TAPS consortium has a built-in "hold" of nine months after the completion of the initial expansion to 1,200,000 barrels a day before beginning to build any further expansion. This can be shortened only by amending the consortium agreement, which requires the approval of all members. To the best of our knowledge this has not been done, although we expect they will almost certainly wish to expand the capacity of the pipeline at an early time. In light of the time between ordering and obtaining delivery of the pumps and other materials needed for the new pump stations, etc. that would have to be built for the expansion, we expect that deliveries through TAPS beyond 1,200,000 barrels a day will only begin sometime in the first half of 1979.

We cannot say whether this further expansion would be to the nominal capacity of 2,000,000 barrels a day, or to something less. The main pool in the Prudhoe Bay field will not be produced at sustained long-term rates in excess of 1.5 to 1.6 million barrels a day. However, the proposed unit operators for the field have expressed their expectation that the main pool may have short-term production peaks of 1,800,000 barrels a day. This would suggest that the expansion of the pipleine would be at least to that capacity.

It is also possible that two other known, large pools in the Prudhoe Bay field -- the Lisburne and Kuparuk pools -- will prove to be economic to produce. Although both are very large accumulations of oil, neither can clearly be characterized as commercial (i.e., economically justifiable to produce) with the present uncertainties of crude oil pricing for the North Slope. We are hopeful that they will be

produced during the 1980s, which would then probably fill the pipeline.

Other West Coast crude oil sources. Information on other West Coast States' projected oil production and on future imports to the West Coast is not readily available to us. Others have published their estimates of what these will be, and all we could provide at this time is a rehashing of their studies.

It is clear, however, that opening the spigot wide at Elk Hills and the new production from the Santa Ynez unit off California do not make easier the task of accommodating the crude oil in PADD V as the State has repeatedly pointed out, the task is not made any easier by an accelerated OCS program.

Refining capacity. The capacities and announced expansion plans for refineries in PADD V are published from time to time in the Oil & Gas Journal. We are in no position to question those reports.

The real question is not what the total refinery capacity is or will be in PADD V, but how much of that capacity can be used to handle oil like that from the North Slope. To answer this question entails a refinery-by-refinery analysis. While we were already pursuing this line of inquiry on our own before your inquiry, this has proved to be a considerable undertaking and is not yet close to completion.

West Coast petroleum demand. Again, we have received the forecasts of others regarding the demand in PADD V for refined products, but we have not conducted an independent study of our own.

However, it is clear, and I would emphasize, that the predictions of a crude oil "surplus" developing in PADD V do not necessarily mean that more crude oil will be available than will be consumed. What the "surplus" probably will be is an availability of crude oil beyond the physical capacity of the refineries to process it. Demand for refined products may well exceed the output of the refineries, and the additional products would have to be brought in from other PADDs or even from other countries. We may well see PADD V "exporting" crude oil that its refineries cannot accommodate, while simultaneously "importing" refined products to meets its consumer demand.

Of course product demand would be a limiting factor in the accommodation of North Slope crude oil if the present

refineries can fill the demand with their present and planned capacities. Present demand in PADD V is near the refiners' capacity, though; so it seems likely that the physical throughput of the refineries will limit the accommodation of North Slope crude, rather than a lower market consumption of refined products.

It seems likely that a crude oil "surplus," in the sense just indicated, will develop in PADD V as Elk Hills production is maximized, as production comes on stream from the California OCS, and of course, as deliveries through TAPS reach 1,200,000 barrels a day. It may range from 400,000 to 600,000 barrels a day initially; and as more OCS production comes on stream and when TAPS is further expanded in 1979, this "surplus" may reach a million barrels a day.

Accommodating the "surplus" oil. The questions in part IV of the questionnaire relate to nine different ways of accommodating the projected oil "surplus" in PADD V by physically transporting it to places outside this District or by restricting its production. Basically these proposals boil down to variations on four basic possibilities: one, a pipeline (or pipelines) across the Rockies from PADD V to the refining and transportation systems of the middle and eastern states; second, marine shipment of the oil to ports on the Gulf of Mexico and Atlantic coasts; third, exchanges of Alaskan oil with other countries in return for their oil (which they either produce themselves or which they have purchased from petroleum-exporting countries) delivered at U.S. ports on the Gulf of Mexico and the Atlantic; and fourth curtailment of North Slope production.

The major selling point for the Kitimat and Port Angeles pipelines is that they will provide relief to the Northern Tier refiners, whose crude supplies from Canada are rapidly being cut off. However, both of these proposals will involve substantial new pipeline construction -- all the way from Kitimat to Edmonton in the first case, and even further (from Washington to Minnesota) in the second. At today's high prices, this construction will be expensive. In addition, it will take time: possibly too much time to save the Northern Tier refiners from the disastrous effects of the phase-out of Canadian crude. These alternatives should not be discarded, but the time and cost limitations placed on us call for faster and cheaper plans.

It may be possible to rescue these refiners through another means, crude oil exchanges with Canada. The cut-backs in Canadian exports to the Northern Tier are occasioned by the

energy shortages beginning to be experienced in Canada's industrialized and populous East. Exchanging Alaskan oil from Canadian crude delivered to the Northern Tier refiners would give Canada oil which it could re-exchange with Japan for deliveries of crude oil to Canada's East Coast which would otherwise have gone to Japan. Exchanges of this complexity are routine for major oil companies, which presumably would be the ones actually effecting the exchanges. If the Northern Tier refiners are to be "saved" in the long run by pipelining Alaskan crude to them, such a system of exchanges could still be set up as a temporary measure to ensure that they continue to have crude oil while the line is being built. On the other hand, a three-way crude oil exchange might prove to be more efficient (less expensive) in supplying oil to those refineries than either of the new and expensive pipelines currently proposed, and if so, it could become the long-term solution to their crude oil supply problem.

The SOHIO project can probably be completed the earliest of the pipeline proposals, which would minimize the duration of the problems arising out of the "surplus." Construction of the SOHIO project would not necessarily preclude another pipeline, if economically feasible, from being built to the Northern Tier. SOHIO envisions 500,000 barrels a day initially going through its proposed system. But as I stated earlier, the padd v "surplus" may reach 1,000,000 barrels a day before 1980. If no other line is built, SOHIO proposes to convert a second natural gas pipeline to take care of this additional "surplus." However, by then the Kitimat or Port Angeles pipeline could have been built, and it would be able to transport this additional oil.

Shipment of the "surplus" oil through the Panama Canal should be considered, if at all, only as a very temporary measure. The biggest tankers that can get through the Canal are 55,000 to 65,000 deadweight tons. Assuming the Average Freight Rate Assessment is computed on tankers of this size at basic Worldscale rates with only a four percent annual rise in rates, the tanker cost through the Canal would be $1.10 in 1978, $1.14 in 1979 and $1.19 in 1980. In contrast, our projections of pipeline tariffs for the SOHIO proposal are only $0.75 for 1978-79 and $0.71 for 1979-80 (midyear to midyear).

In light of the political climate of Latin America and the problems that periodically arise over the continued American ownership of the Panama Canal, it seems doubtful that a Central American pipeline would be sufficiently secure to be in the national interest in the long run.

The notion of desulfurizing North Slope oil at Valdez to make it acceptable for Puget Sound refineries is economically unfeasible. Its cost would likely be almost as great as the total cost of converting the sweet-oil refineries to a sour-oil capability. Moreover, even if they were refitted, the Puget Sound refineries would not absorb the likely "surplus."

As for curtailments of production, the State of Alaska will regulate and control North Slope production practices and rates to assure the greatest ultimate recovery of the hydrocarbon resources there and to prevent their waste. To the extent the PADD V "surplus" may bear on these objectives, it will be a consideration in this.

As indicated earlier, Canada could find a tripartite oil exchange with the U.S. and Japan to be to its advantage in supplying crude oil where it is needed in a way that avoids more costly distribution alternatives. Similar advantages appear to exist in a bipartite exchange between the United States and Japan. Oil already committed to Japan could be diverted for delivery at American ports, avoiding building any new expensive pipelines; in exchange, crude oil beyond the refining capacity of PADD V would be shipped from the District to Japan. As a means of achieving crude oil distribution throughout the Nation without the build-up of local surpluses, these exchanges would be less expensive than the alternatives. But it does have other implications, of which you are undoubtedly aware, and would require satisfaction of the terms of the TAPS Authorization Act which was intended to act as a disincentive to any export whatever.

Costs and prices. Including interest on funds used during construction, our estimated cost for TAPS with a capacity of 1,200,000 barrels a day is $9.3 billion (assuming it comes on stream as scheduled). We estimate that it would cost an additional $575,000,000 to expand its capacity to 1,600,000 barrels a day and $995,000,000 to enlarge it from 1.2 to 2.0 million barrels a day.

Forecasting tariffs for TAPS is complicated by the fact that eight pipeline companies will be sharing the one physical system. Each company may treat its costs in its own way and on the basis of its own experience in building the pipeline, and it is by no means assured that all eight will have the same tariff. Consequently our tariff projections, which are modelled as if only one company owned and operated the pipeline, have a certain element of uncertainty built into them. Actual tariffs may not be what we predict for the average.

The following table indicates our latest composite tariff projections; please note that the years used are Alaska's fiscal years, which run from midyear to midyear (e.g., Fiscal Year 1978 begins July 1, 1977 and ends June 30, 1978).

Fiscal Year	Tariff ($/bbl)	Average Daily Thru'put (MMB/D)
1978	4.84	0.95
1979	5.34	1.30
1980	4.43	1.60
1981	4.13	1.70*
1982	3.86	1.80*
1983	3.72	1.90*
1984	3.58	1.90*
1985	3.54	1.90*

*NOTE: Assumes throughput from other pools in addition to that from the main Prudhoe Bay pool.

The tanker tariffs from Valdez to U.S. ports on the West Coast have an even greater tendency for dispersion than the TAPS tariffs, because of the extreme volatility of supply and demand in the tanker charter market, the variation in fuel consumption and other operating characteristics from ship to ship, the differences in the ages of the vessels, and port of destination, etc. Our projections seek to find a representative weighted average tanker tariff from Valdez to the West Coast, rather than a ship-by-ship, port-by-port projection. As a result, our weighted average may very well fail to correspond to the actual tanker tariff for any particular tanker going to a particular destination; however, our results should fall into the mid-range of the spectrum of tariffs that would be developed by a ship-by-ship, port-by-port analysis. Our latest tariff projection follows (again, note that these are projected by fiscal year, not calander year):

Fiscal Year	Tariff ($/bbl)
1978	0.54
1979	0.56
1980	0.58
1981	0.61
1982	0.63
1983	0.66
1984	0.68
1985	0.71

At the present time our projections indicate that if the wellhead value of North Slope oil is allowed to be determined on the basis of the cost at the refinery for alternative oil of similar characteristics (i.e., Saudi Arabian oil), minus the cost of transporting the North Slope oil from the field to the refinery gate -- then, in that case, the resulting wellhead value will be less than the weighted average domestic oil price. Inclusion of Prudehoe oil in the computation of the weighted average price would therefore allow an offsetting increase in price for other domestic production.

The following table shows our projected wellhead values for Prudhoe Bay and the weighted average domestic oil prices (assuming 10% annual increases):

Fiscal Year	Prudhoe Bay Wellhead Value ($/bbl)	Weighted National Average Price ($/bbl)
1978	8.39	8.96
1979	8.39	9.86
1980	10.19	10.84
1981	11.19	11.93*
1982	12.61	13.12*
1983	13.81	14.43*
1984	15.05	15.81*
1985	16.24	17.46*

*NOTE: Price controls under which this figure is calculated are scheduled to expire before this time; the number is projected for information purposes.

The table appended to this letter, and its accompanying notes, should explain how the Prudehoe Bay wellhead values tabulated above were developed.

I trust that this information will be useful to you and your respective Committees.

Sincerely,

Jay S. Hammond
Governor

Attachment

PRUDHOE BAY WELLHEAD $/B

FISCAL YEAR	ARABIAN CRUDE RAS TANURA (1)	TANKER TARIFF (2)	REFINERY PRICE (1+2)=(3)	LOWER 48 PIPELINE TARIFF (4)	TANKER TARIFF (5)	TAPS TARIFF (6)	TOTAL TARIFFS (4+5+6)=7	PRUDHOE BAY WELLHEAD VALUE (3-7)=8
1976	11.09(a)	1.59(b)	12.68		.50(c)	---	---	---
1977	11.59	1.65	13.24		.52	---	---	---
1978 I	12.14	1.72	13.86	---	.54	4.84(d)	5.38	8.48
1978 II	12.14	1.72	13.86	---	.54	4.84	5.38	8.48
1978 III	12.87	1.90(e)	14.77	1.10*(f)	.54	4.84	6.48	8.29
1978 IV	12.87	1.90	14.77	1.10*	.54	4.84	6.48	8.29
1978	12.51	1.81	14.32	.55	.54	4.84	5.93	8.39
1979 I	12.87	1.98	14.85	.75(g)	.56	5.34	6.65	8.20
1979 II	12.87	1.98	14.85	.75	.56	5.34	6.65	8.20
1979 III	13.26	1.98	15.24	.75	.56	5.34	6.65	8.59
1979 IV	13.26	1.98	15.24	.75	.56	5.34	6.65	8.59
1979	13.07	1.98	15.05	.75	.56	5.34	6.65	8.40
1980	13.85	2.06	15.91	.71	.58	4.43	5.72	10.19
1981	14.68	2.14	16.82	.89	.61	4.13	5.63	11.19
1982	15.56	2.23	17.79	.69	.63	3.86	5.18	12.61
1983	16.49	2.32	18.81	.62	.66	3.72	5.00	13.81
1984	17.48	2.41	19.89	.58	.68	3.58	4.84	15.05
1985	18.53	2.51	21.04	.55	.71	3.54	4.80	16.24

ASSUMPTIONS

(a) The effective state sales price published for Saudi Arabian Heavy crude oil (28.2° API and 2.84% sulfur) serves as a benchmark F.O.B. market value at Ras Tanura for similar quality Alaskan Sadlerochit crude oil (26.8° - 27.2° API and 1.04% sulfur). During fiscal year 1976, actual F.O.B. prices for this crude oil export stream averaged $11.09 per barrel. In late December 1976 or early January 1977, world oil prices will probably be increased by 10%-15%. Assuming that the effective state sales price for Arabian Heavy is increased by 10% in the next four months, the average annual market price for this crude oil export stream will be $11.59 per barrel during fiscal year 1977. Each year thereafter, nominal dollar crude oil market prices are projected to increase at a rate equal to world inflation rates expected during the forecast period (i.e., 6% per annum).

(b) Tanker transportation tariffs for the PG/USWC route during fiscal year 1976 were approximately $1.59 per barrel when computed on an average annual AFRA basis. While the current world tanker market depression could continue to suppress tanker tariffs in the future, tariff rates in this forecast are projected to cover increases in variable costs per annum. Consequently, tanker tariffs are increased 4% per year from average annual base rates computed for fiscal year 1976.

(c) Tanker tariffs for the Valdez/USWC trade are computed on a weighted average basis according to port of destination and throughput volume. As in the case of foreign flag tankers, tariffs are increased 4% per annum from the composite base rate computed for operations in fiscal year 1978.

(d) In this production scenario, throughput assumptions for TAPS include production from fields other than the main Prudhoe Bay reservior. Under current economics conditions, these fields may be marginal investment opportunities. Throughput assumptions for TAPS by fiscal year of operation are (in millions of barrels per day): 1978 - .95, 1970 - 1.3, 1980 - 1.6, 1981 - 1.7, 1982 - 1.8, 1983 - 1.85, 1984 - 1.9, and 1985 - 1.9. Total capital costs for TAPS (Phase II) are projected to be $9.3 billion. Expansion to TAPS (PHASE III) would require an additional $995 million.

(e) In this distribution scenario, the primary refinery market for Alaska Sadlerochit crude oil production is assumed to shift from PADD V to PADD III in the third quarter of fiscal year 1978. Accordingly, the tanker tariff rate base changes from PG/USWC to PG/USGC. This results in both higher tanker tariffs and higher C.I.F. refinery market prices for Alaskan Sadlerochit crude oil production. Subsequent tariffs increase 4% per annum.

ASSUMPTIONS

(f) In this distribution scenario, limited volumes of Alaskan Sadlerochit crude oil production are forced into U.S. refinery markets other than PADD V by utilizing small tankers capable of passage through the Panama Canal. Short-term, incremental tanker transportation tariffs are projected for limited volumes and duration in a route from Long Beach, California to the U.S. Gulf Coast. Note: this system is not a viable long-term distribution system.

(g) In this distribution scenario, the proposed SOHIO - EL PASO natural gas pipeline to crude oil pipeline conversion project is assumed to meet an attainable construction schedule and to begin operations in mid-1979. Total capital costs for this project in a Phase I configuration are approximately $500 million. Expanded to its Phase II capacity, this system could cost $800 million.

STATE OF CALIFORNIA—THE RESOURCES AGENCY EDMUND G. BROWN JR., Governor

ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION
1111 HOWE AVENUE
SACRAMENTO, CALIFORNIA 95825
(916) 322-3690

September 14, 1976

Mr. William Van Ness
Chief Counsel
Interior Committee
U. S. Senate
Washington, D.C. 20510

Dear Mr. Van Ness:

Governor Brown has asked me to give you my personal response to the questions posed in the letter of August 23, 1976, from Senators Magnuson, Jackson and Stevenson.

The enclosed comments on question IV of your "Questionnaire: Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope" summarize our current perceptions. While many of the questions raised have yet to be comprehensively studied, the following items reflect the principle thrust of these remarks:

(1) Temporary and even long-term exchanges of crude oil between U. S. and foreign (principally Canadian and Japanese) refineries appear to be a reasonable and economic solution to both the projected Northern Tier crude shortage and the West Coast crude surplus. Such exchanges enable transportation and crude acquisition cost savings to all parties. If properly arranged, they could also generate significant savings for consumers. Concerns about increased reliance on foreign crude sources resulting from exchanges appear to be eliminated by the International Energy Program under which all participants have agreed to pool and share their crude oil resources in the event of a producer embargo or production cutback.

Therefore, exchange solutions should be more carefully and objectively evaluated with respect to overall national economic costs and benefits before being prematurely rejected for ill-defined and questionable "national security" reasons.

(2) As presently configured, the SOHIO/El Paso "West Coast-Mid-continent Pipeline Project" appears to have questionable permit prospects due to air quality and natural gas supply concerns.

The natural gas concerns will not be fully allayed until the Federal Power Commission (FPC) decides which competing Alaskan natural gas transportation system should be constructed. The air quality problems of siting a large crude oil receiving terminal in one of the nation's worst air quality regions will not be resolved until all alternatives (terminal sites in California, crude oil exchanges, pipeline routes, and tanker routes) have been more carefully and objectively evaluated.

The Congressional mandate to open Elk Hills (Naval Petroleum Reserve No. 1) production is also related to the FPC SOHIO/El Paso abandonment proceedings. If abandonment is permitted, the Navy should construct a pipeline from Elk Hills to Redlands, California, instead of from Elk Hills to Port Hueneme (Oxnard, California). The former would efficiently move surplus Elk Hills oil to other markets; the latter would only require yet another unnecessary crude oil marine terminal and expose California's coastline to greater oil spill risks and damage.

Therefore: (a) the FPC should continue to phase its decision-making so that the Alaskan gas transportation decision is made before the SOHIO/El Paso abandonment decision; and

(b) the Navy Department should defer its final decision on the routing of an Elk Hills pipeline until the FPC SOHIO/El Paso abandonment decision is resolved.

The logical phasing of these three major energy supply decisions requires a careful coordinated national energy policy. Without it, it is difficult for the State of California to respond to national needs and at the same time protect the best interests of its citizens.

(3) Based on the best information available, the proposed Trans-Provincial pipeline system appears to be the "best" permanent pipeline solution to the Northern Tier crude shortage problem. Coupled with exchanges, an expanded (36" vs. the planned 30" pipeline capable of handling 600-900 MB/D) Trans-Provincial pipeline would probably place surplus Alaskan oil where it is and would be needed most (the Northern-Midwest refinery regions) at the least cost. This option is appealing for at least two important reasons:

(a) Because it requires only one permit from the Canadian National Energy Board, Trans-Provincial does not require U.S. federal intervention to streamline or override state/local permit processes. This single permitting feature, coupled with the relative environmental advantages of the Kitimat marine terminal site, greatly enhances the prospects of this pipeline being quickly permitted and constructed.

(b) It is supported by most large Northern Tier refineries.

Therefore, the U.S. federal government should encourage the construction of the Trans-Provincial Pipeline at a size larger than presently proposed through negotiations with Canada and prompt approval of all exchange agreements. An expanded Trans-Provincial Pipeline would serve both U.S. and Canadian national interests and would make beneficial use of existing spare capacity in the Interprovincial Pipeline system.

Rob Solomon of our staff will be in Washington next week and will contact you for further discussion on these issues. Robert Shinn, who directed a recent FEA study on these questions and recently joined the Energy Commission staff as my advisor this month, will be available for consultation by telephone at (916) 322-3690.

Sincerely,

RICHARD L. MAULLIN
Chairman

RLM:kl

Attachment

ATTACHMENT

1. TRANS-PROVINCIAL

Trans-Provincial informs us that they anticipate making their application to the Canadian National Energy Board (NEB) before the end of this year. The proposed 24-month construction time estimate appears to be reasonable. This gives Trans-Provincial relatively favorable timing, especially since no serious permit challenges are currently anticipated. Announced participation by Northern Tier refiners, and provincial government support in British Columbia, are further positive indications. Only a single permit will be required from the NEB.

Other favorable considerations include:

° Significant savings in tanker costs would be realized via Trans-Provincial for crude oil shipments originating in Alaska (about 500 MB/D).

° A moderate amount of required new pipeline construction.

° The project would utilize existing spare capacity (about 500 MB/D) in the Trans-Provincial pipeline.

° Marine environmental and navigational conditions at Kitimat appear relatively favorable. Port facilities would be sized to accommodate up to 320,000 dwt tankers.

° Trans-Provincial (unlike Northern Tier) would be consistent with construction of the proposed SOHIO project, if the latter is permitted; thus, Trans-Provincial is a good "hedge", since there will probably not be a large enough crude oil surplus to support both the Northern Tier pipeline (at 800 MB/D) and the SOHIO/El Paso project (at 500 or 1,000 MB/D). In addition, there would be national security benefits of a dual trans-continental pipeline system.

° There appears to be little, if any, local opposition to the development of tanker facilities at Kitimat, British Columbia. In addition, the major industrial entity in the area supports the project as it will contribute to the local tax base.

° Total financing requirements will probably be under $500 million, for a 30" line; construction of a 36" line would increase costs about 20%, while enabling ultimate capacity increase of 50% or more.

° The tariff and cost estimates as proposed by Trans-Provincial, are consistent with most industry assessments. The Northern Tier Pipeline Company estimates, on the other hand, have been subject to question.

° Trans-Provincial appears to be the project most likely to materialize without government intervention.

On the negative side, it could be an unfortunate "missed opportunity" if the Trans-Provincial line is sized at 30" due to the limited requirement and understandable desire of the participants to economize on construction costs, when there may be a need for a 36" line -- especially if SOHIO cannot be permitted. Canadian and U.S. governmental authorities should encourage construction of the larger line. A 36" line would provide more pipeline flow flexibility. Actual flows could be varied.

2. NORTHERN TIER

The Northern Tier project would offer a direct means of supplying Alaskan and foreign crude to all Northern Tier refineries.

With its high (800 MB/D) capacity, Northern Tier will be hard-pressed for crude shippers if the SOHIO project is permitted at 500 MB/D capacity,and put in an impossible situation of Phase II is permitted at 1,000 MB/D. Forecast surpluses for future years are too uncertain to support construction of two large capacity systems.

The favorable prospects for Trans-Provincial, and Trans-Provincial's apparent headstart in timing, tend to reinforce this conclusion.

The Northern Tier project would be the most expensive (probably in excess of $1 billion) of the competing land pipeline systems, involve the most new construction, and would have a relatively long completion time -- at least 30 months.

Northern Tier has had difficulty (and lost several months' time) in submitting an acceptable permit application to the Washington State Energy Facilities Siting Council. Multiple state permits and a Federal Environmental Impact Statement are required for this project.

Port facilities at Port Angeles are a critical feature of the proposal, but the need for such facilities cannot be conclusively demonstrated until the Arco versus Evans case has been resolved -- probably on appeal to the Supreme Court. State and local support for the siting of a terminal at Port Angeles are conditioned on its use by Puget Sound refineries. The state does not now have any tool to force this use and the economics are not favorable. Puget Sound refineries would: (1) have to be constrained to the use of tankers smaller than 100 mdwt; and, (2) have access to large (greater than 180 mdwt) tankers before the use of Port Angeles over direct deliveries to the refineries would save the same per barrel as the proposed pipeline tariff ($ .19 Bbl) between Port Angeles and Anacortes/Chevy Point.

While per barrel transportation to inland refineries would appear to be comparable vis-a-vis Trans-Provincial (for example, see the table on page x of FEA's August, 1976 summary report on "Crude Oil Supply Alternatives for the Northern Tier States"), they are less favorable on a capacity-normalized basis.

On the positive side, the Northern Tier pipeline would make extensive use of existing rights-of-way, would entail substantial construction benefits for the U.S., would offer possible access to Northern Tier

strategic storage, and would not be subject to uncertainties of the Canadian permitting process. Lamentably, the uncertainties in the Canadian permitting process, however, seem to be more manageable than our own. In conclusion, Northern Tier appears attractive only if SOHIO's Southern Tier proposal is definitively withdrawn, but timing works against this outcome.

3. SOHIO

The SOHIO project has been the subject of great controversy and extensive press coverage in California. The issue which has received the greatest attention with respect to SOHIO is the impact of marine terminaling operations on air quality in the South Coast (Los Angeles) Air Basin. The resolution of this question is not predictable until all relevant environmental studies and consultant reports have been released and thoroughly reviewed by all sides. The controversy is serious enough to place the status of the project in doubt. For this reason, it would appear to be unwise (from a policy point of view) to expect quick and favorable resolution.

The SOHIO/El Paso project must pass through three major permitting processes, each on a different timeline. The Bureau of Land Management will soon complete its extensive draft EIS, the final due in February/March 1977. In roughly the same period, the Port of Long Beach-State Public Utilities Commission draft EIR (Environmental Impact Report, under the California Environmental Quality Act) will also be completed. The Federal Power Commission proceeding on the abandonment of the El Paso natural gas line proposed for conversion is roughly in mid-stream.

The SOHIO/El Paso project would take about 2 years to construct, the main bottleneck being the construction of marine terminal facilities in Long Beach. It is also apparent that SOHIO is not the answer to the special problems of the Northern Tier states, which must be addressed separately.

The other major issues with respect to SOHIO is its impact on future availability of capacity to transport new natural gas supplies into the state. While most analysts agree that the Phase I abandonment of 500,000 B/D capacity would not be likely to limit this capacity under most supply scenarios, most also agree that the State's future access to natural gas transportation could be seriously eroded under a Phase II abandonment (over 500,000 barrels per day).

While Phase II would be the subject of a separate FPC proceeding, given the range of current oil "surplus" forecasts, a Phase II application would seem inevitable, and would probably be granted in spite of California's objections. This issue could be resolved after the decision on the transportation of Alaskan gas, since a deficit gas transmission capacity is likely only if California must receive its "share" of Alaskan gas by displacement through the El Paso/Trans-Western systems.

If the FPC abandonment decision is deferred until after the resolution of the Alaskan gas issue, debate on this point could be closed. Alternatively, if the national administration could make an ironclad commitment to the construction of a "western leg" gas delivery system if a land pipeline route is selected for Alaskan gas transportation, the State's resistance on this point would probably end, since the "displacement" requirement would be removed.

The State of California faces another generally unrecognized dilemma with respect to the SOHIO project: its relation to the Congressionally-mandated requirement for the Navy to have a 350,000 B/D crude oil transportation system completed by April, 1979 (three years from enactment of the Naval Petroleum Reserves Production Act of 1976). To minimize environmental impacts within the State, it would be preferable to have the Navy construct its pipeline to connect with the SOHIO/El Paso line, if permitted. On the other hand, the Navy must make its decision relatively soon -- in all likelihood, before the SOHIO controversy is resolved.

In the face of this uncertainty, the Navy will probably choose to meet its deadline by selecting the route which maximizes flexibility-transportation of Elk Hills crude via a marine terminal at Port Hueneme, near Oxnard, California, with much greater negative environmental impacts with respect to both air quality and vessel traffic. In this case, too, the decisions appear to be in precisely the wrong sequence: California and the nation would benefit if the Alaskan gas decision could be made first, <u>then</u> the decision on SOHIO; and, <u>lastly</u>, the decision on how to move the Navy's Elk Hills production. The adjustments in timing, by a few months, would offer great benefits at very little cost.

4. OTHER ALTERNATIVES

We have not exhaustively studied the other alternatives listed. The State of California will carefully review all federal studies, particularly FEA's, before making permanent policy decisions. There seems to be general agreement that some of the "surplus" crude will find its way eastward through the Panama Canal, in small tankers. There appears to be doubt as to the availability of sufficient Jones Act tanker capacity for this purpose, and there has also been debate over how much it will cost. Regardless of how much it will cost, the Panama Canal is likely to be one element of a temporary solution.

To meet Northern Tier demands, from a purely analytical point of view, a system of crude exchanges would definitely be the most rational solution, perhaps permanently for some areas, and temporarily (until completion of Trans-Provincial) for others.

Given the environmental costs of trans-shipment of Alaskan oil from the west coast to mid-continent, a carefully managed program of crude exchanges with Japan or other willing buyers does not seem contrary to the national interest. Political opposition to a crude exchange program should not stand in the way of thorough analysis of both the cost and benefits of this option, which we understand are currently being explored in considerable detail by FEA.

STATE OF WASHINGTON
OFFICE OF THE GOVERNOR
OLYMPIA

DANIEL J. EVANS
GOVERNOR

September 13, 1976

The Honorable Warren G. Magnuson
127 Old Senate Office Building
Washington DC 20510

SEP 22 1976

The Honorable Henry Jackson
137 Old Senate Office Building
Washington DC 20510

The Honorable Adlai E. Stevenson
456 Russell Senate Office Building
Washington DC 20510

Gentlemen:

In response to your letter of August 23 pertaining to the disposition of Alaskan crude oil and the problems associated thereto, I would like to submit the attached information as requested. This information is keyed to the questionnaire contained in your original request. Of necessity, we are unable to comment on many aspects of the questionnaire, but where possible, have supplied information which will hopefully be of assistance in your deliberations in this regard.

I would like to again emphasize our basic position as regards the movement of crude oil into and on Puget Sound. Our primary problem is to insure such movements are handled in the most environmentally sound manner. If this can be done only by prohibiting the movement of tankers into the inner sound, that is the way we propose to proceed. The construction of a pipeline alternative, either the Northern Tier proposal calling for a discharge facility at Port Angeles, or the Transprovincial proposal, calling for a discharge facility at Kitimat, with attendant movement of crude to our refineries via the Transmountain pipeline, would suffice to meet this objective.

All the other proposals mentioned in paragraph IV, with the exception of item sub 9, are of little interest to us. If exchanges with Canada can be realized so that continued support of our refineries can be made through the existing Canadian pipeline system, then our basic objectives will be met. We consider this option highly unlikely, so must look to either the Northern Tier or Transprovincial proposals as the ultimate solution to our problem.

Thank you again for your interest and concern in this matter and I trust that eventually the problems will be solved to the satisfaction of all interested parties.

Sincerely,

Daniel J. Evans
Governor

DJE:nl
Enc.

9-10-76

RESPONSE TO SELECTED QUESTIONS
POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY
OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

I.B.1 Current Refinery Capacity - Puget Sound Area

Arco	96,000 b/d
Mobil	71,000
Shell	91,000
Sound Refining*	4,500
Texaco	78,000
U. S. Oil Ref.**	21,400
Total	362,000 b/d capacity

*asphalt is primary product
**products marketed by Time Oil Co.

Throughput - 1975: about 80% of capacity; 1975 deliveries were 179,000 b/d by Canadian pipeline and 109,000 b/d by tanker of foreign crude. Refined products are both exported and imported from Puget Sound area by tanker.

I.B.2 Current projections - Puget Sound area and Portland area (Oregon)

a. The above, plus possible expansion by Mobil; plus
b. By the mid-80s, possible new, grass-roots refinery at the Ferndale site owned by Standard Oil Company of California; plus
c. Two possible new, low-complexity refineries in the Portland area: Charter Energy Company, 52,000 b/d, at St. Helens; Cascade Energy Inc., 30,000 b/d, at Rainier. These would displace some of Washington's export to Oregon via Olympic Pipeline.

I.B.3 Ability of Puget Sound refiners to process Alaskan North Slope crude types, est. for 1978

Arco	96-98,000 b/d
Mobil	10-35,000 b/d
Shell	0-15,000 b/d
Texaco	0-2,000 b/d
U. S. Oil	- 0 -

Estimated total North Slope crude to Puget Sound refiners: 125,000 to 131,000 b/d in 1978

II.A Current Demand - State of Washington

Note: Forecasts are in trillion Btu/yr (TBtu)

		Tbtu
1975	Motor and aviation gasoline	195
	Distillate, except diesel	89
	Diesel	19
	Residual	58
	LPG	7
	Kerosene, except jet fuel	1.5
	Jet fuel	40
	Total - Washington	409.5 Tbtu

1980

Total petroleum for transportation	377
Total petroleum, non-transportation	178
Total - Washington	555 Tbtu

1990

Total petroleum for transportation	546
Total petroleum, non-transportation	203
Total - Washington	749 Tbtu

IV. A. & B. Proposed Responses to Projected West Coast Surplus

Option 1 (Kitimat - Edmonton pipeline)

Status Timing - NEB and provincial approvals could be obtained in 1977; (proposal goes to NEB Oct. 1, hearings start Jan. 1) completion 1979-80? We believe B.C. government will be behind it. The pipeline company and the owner-shippers are serious, unlikely to temporize.

Costs - may be lowest cost for all concerned; especially over a 20-30 year operating period. Reasons include: shorter route from Valdez, VLCC capability, shorter pipeline route, high utilization of existing pipelines beyond Edmonton.

Financing - appears solid because owner-shippers provide both access to capital and guaranteed market.

Environmental- very favorable. With the absolutely essential spur to Puget Sound refineries via existing Transmountain pipeline, this alternative removes the bulk of tanker traffic from both U. S. and Canadian waters of high resource value and sensitivity to spills/pollution.

Others: Security - No real risk, because far more Canadian hydrocarbons do, and will, pass through U. S. territory. The Sarnia pipeline will eventually be reversed, and all of eastern Canada will be supplied through U. S. ports. Also, this link completes Canada's access to Pacific crude, thus greatly aiding Canada's own security.

Option 2 (Northern Tier Pipeline)

Status Timing - Application accepted by Washington Energy Facility Siting authority. Company assembling options on terminal site in Port Angeles. Considerable local opposition. Still appears that no customers (refiners) have signed up, which would delay financing and construction indefinitely.

Costs - Fairly high due to length of line, right-of-way acquisition in some areas and probable construction delays.

Financing - Unless the two railroads guarantee it, could be problematical at best.

Environmental - It reduces greatly tanker traffic on inner sound waters, beneficial to both U. S. and Canada.

Option 3 (SOHIO - Southern California pipeline reversal)

Environmental - California air quality limits could be exceeded by crude storage onshore, which would scuttle the project. If the project does go, then both Washington and British Columbia would face greater difficulty in reducing tanker traffic in their sensitive marine areas.

Costs - Would appear to raise costs to all Northern Tier refiners except those on Puget Sound - or put them out of business.
Financing - SOHIO appears greatly extended, and getting Alaskan crude to Midland, Texas, does not really solve the problem for the company.

Options 4, 5 - Panama, Guatemala, Cape Horn
Environmental - Long tanker routes mean higher risk exposure
Costs - Appear excessive except in the very short term, through any combination
Security - Shaky for both Panama and Guatemala

Option 6 (refinery retrofit)
Environmental - Increases sulphur content in refined products unless expensive technology is installed. Fosters the "drain America first" concept. Requires longer tanker routes.
Costs - Increases costs across the board
Other - Requires either incentive or compulsion to convert refineries of non-Alyeska members, who are interested in processing their own crude.

Option 7 (desulphurization facility)
General Comment - Appears to be little enthusiasm in the industry, suggesting federal financing or guarantee. Does not attack the problem of transshipment to interior states.

Option 8 (shutting-in)
General Comment - Disastrous both to State of Alaska and to extended companies, e.g. SOHIO.

Option 9 (exports or exchanges)
General Comment - North Slope crude is not wanted by Western Canadian refiners, who are set up to handle Alberta sweet. In Japan, it would have to compete with Indonesian and Arab crude, and there would be severe penalties for the high sulphur content. But exchanges with eastern Canadian refiners are very helpful to all Northern Tier refiners, lowering costs and buying time for planning.

C. Implementation

The Kitimat-Edmonton pipeline with a spur connecting it to the TransMountain pipeline to Puget Sound offers a combination of feasibility, environmental protection and flexibility for the supply systems of both the U. S. and Canada.

The Northern Tier pipeline is an acceptable alternative, assuming that financing and schedule problems are resolved; if they are not, then the whole North Slope delivery schedule could be postponed (relative to full capacity) with serious consequences.

The SOHIO plan, which includes a reversal of an El Paso gas pipeline, appears beset with serious problems and potential delays in completion.

None of the other options is as attractive as these three, however.

D. Federal Policy Role

1. With none of the three pipelines in place, it appears that only a combination of the central desulphurization facility at Valdez and and exchanges with Canada would be workable, and not particularly attractive at that. ERDA could guarantee the desulphurization plant, but the cost would require federal legislation. Considering the enormous scale of such a plant, and the special problems of construction there, it could have real timing problems of its own. Desulphurization at any other site would be hopelessly impractical, requiring a second transshipment and very large onshore storage facilities for both crude and partial products.

2. In addition to the serious objections to exports cited above, it does not appear likely that any other country would take on Alaskan crude without long-term supply guarantees, including guaranteed delivery in a period of OPEC embargo. PADD-V would be virtually wiped out in such an emergency with no access to Alaskan crude.

3. If the Kitimat option can be exercised, State Department should show more activity in concluding the U. S. - Canadian Hydrocarbon treaty, and the industry schedule should be accelerated by all practical means (short of legislation).

   The next alternative, not particularly desirable, would be a federal pipeline system to supply interior refiners, along the lines of Bonneville or TVA. The required legislation would then address the terminal siting and routing questions from the environmental aspect, based on "least possible risks" as the uppermost criterion.

Alyeska pipeline SERVICE COMPANY

1835 SOUTH BRAGAW STREET (99504) P.O. BOX 4-Z (99509) ANCHORAGE, ALASKA TELEPHONE (907) 278-1611, TELEX 090 25 127

September 15, 1976

The Honorable Henry M. Jackson
Chairman
Committee on Interior and Insular Affairs
United States Senate
Washington, D.C. 20510

Dear Senator Jackson:

This will respond to your letter dated August 23, 1976 and accompanying questionnaire requesting information with respect to potential problems associated with delivery of crude oil from Alaska's North Slope. In accord with your request, we respond to all questions as to which we have information which might be useful to the committees reviewing this matter.

I. West Coast Petroleum Supply

A. Crude Oil

1. Alaska

a) What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska pipeline?

Our best current estimate of the date first delivery of North Slope crude oil will be made through the Trans-Alaska Pipeline to the terminal at Valdez remains the summer of 1977. While we have previously referred to mid-summer and July 1977, we have not attempted to specify a particular day, week or even month for first delivery of North Slope crude oil at Valdez. However, we believe that first delivery will surely take place prior to the middle of September, and it still appears to us that the most likely date will be in July 1977.

b) To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

This estimate takes into account all of the questions now being raised concerning pipeline welds and other potential and anticipated technical delays. Of the less than 4,000 welds questioned by our audit of radiographs of 1975 welds, some 3,390 have been resolved by repair and other remedial means to this date. We have recently requested exemptions for some 600 relatively inaccessible welds which our fracture mechanics studies have indicated are quite acceptable from

the standpoint of strength and integrity of the welds and of the Pipeline System. In addition, we have attempted to avoid delay by proceeding early to repair and otherwise resolve these welding questions. As a result, we feel confident that they will not delay completion of construction of the Pipeline System and delivery of first crude oil through the System to the terminal at Valdez. While other construction and technical problems remain to be solved, none of them appear at this time to hazard delivery of first crude oil through the System to the terminal at Valdez on schedule.

c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

Our current projections of deliveries of North Slope crude oil at Valdez are:

Mid 1977 - Late 1977: 600,000 barrels per day

Late 1977 until expansion of Pipeline System: 1.2 million barrels per day

These quantities will be reduced by withdrawals from the System for the following:

1) Connections are being installed in the mainline pipe near Pump Station No. 8 to service the requirements of Energy Company of Alaska for its refinery near North Pole, Alaska. This requirement will result in net withdrawal from the System of approximately 15,000 barrels per day.

2) Pump Stations No. 5, 6, 8, 9, 10 and 12 will be fueled by turbine fuel produced from crude oil withdrawn from the System. We estimate that requirement will be 4,200 barrels per day when the System operates at 1.2 million barrels per day capacity.

These projections are based upon System capacity of 1.2 million barrels per day, the capacity presently authorized by the Owners of the System.

V. Costs and Prices

A. What is the full anticipated cost of constructing and equipping the Trans-Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?

The current anticipated cost of constructing and equipping the Trans Alaska Pipeline System and terminal facilities to transport 1.2 million barrels per day is $7.7 billion. This does not include interest costs, which are incurred by Owners in financing conducted independent of Alyeska's construction activity. This is the current cost forecast published by Alyeska Pipeline Service Company based upon our present completion schedule, and it appears to us at this time to be a reasonable estimate of the cost of constructing the System to a capacity of 1.2 million barrels per day.

B. What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985. (Specify throughput assumptions)? What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?

Each of the Owners of the Trans Alaska Pipeline System will operate its undivided share of the System as a common carrier under the Interstate Commerce Act and regulations promulgated pursuant thereto by the Interstate Commerce Commission. It is contemplated that Alyeska Pipeline Service Company will act as Agent for the Owners in the physical operation of the Pipeline System, but will have no function to perform with respect to filing tariffs or collecting tariff charges. Each Owner will file separate tariffs in accord with those regulations. Alyeska Pipeline Service Company has no information with respect to anticipated crude oil transportation pipeline tariffs or tanker rates that will be applicable to transportation of crude petroleum.

The answers above provide all of the information we have in response to the questions set forth in your questionnaire. If we may be of further assistance, please advise.

Respectfully submitted,

ALYESKA PIPELINE SERVICE COMPANY

E. L. Patton

E. L. Patton
Chairman and Chief Executive Officer

ELP:lm
cc: Honorable Warren G. Magnuson
Chairman, Committee on Commerce

Honorable Adlai E. Stevenson
Chairman, Special Subcomm. on Oil &
Natural Gas Production & Distribution

AtlanticRichfieldCompany

1025 Connecticut Avenue, N W
Washington, D.C. 20036
Telephone 202 457 6210

Hollis M. Dole
Washington Representative

November 11, 1976

William J. Van Ness, Esq.
Chief Counsel
Committee on Interior and Insular Affairs
United States Senate
3204 Dirksen Senate Office Building
Washington, D. C. 20510

Attn: Ms. Betsy Moler

Dear Mr. Van Ness:

Subsequent to the Committee's publication of the responses to the questionnaire entitled "Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope," Atlantic Richfield Company has reevaluated its position with regard to the confidentiality of responses to Questions I-A2(b) and III-A,B.

Atlantic Richfield Company requested confidential treatment at the outset as the responses, in part, reflected both proprietary analyses and assumptions sensitive to competition, as I indicated in my September 21 letter to you. A review of publicly available data now permits us to conclude that the release of this information now would not put Atlantic Richfield Company at a competitive disadvantage. We, therefore, authorize the release for public dissemination of our complete responses to Questions I-A2(b) and III-A,B, as well as other responses we provided.

Very truly yours,

Hollis M. Dole

cc: S. Lynn Sutcliffe, Esq.
General Counsel
Commerce Committee

HENRY M. JACKSON, WASH., CHAIRMAN
FRANK CHURCH, IDAHO
LEE METCALF, MONT.
J. BENNETT JOHNSTON, LA.
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GRENVILLE GARSIDE, SPECIAL COUNSEL AND STAFF DIRECTOR
WILLIAM J. VAN NESS, CHIEF COUNSEL

United States Senate
COMMITTEE ON
INTERIOR AND INSULAR AFFAIRS
WASHINGTON, D.C. 20510

September 28, 1976

Mr. Hollis M. Dole
Washington Representative
Atlantic Richfield Company
1025 Connecticut Avenue, N.W.
Washington, D. C. 20036

Dear Mr. Dole:

I appreciate your prompt response to my telephoned request that Atlantic Richfield clarify its position with respect to a request for confidentiality contained in the September 17 response to the questionnaire entitled, "Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope."

It is our intention to publish the responses to the questionnaire received from all parties. In accord with your request of September 21, I have substituted for publication your responses which deleted some of the information provided on September 17 in response to questions I(A)(2)(b) and III(A-B).

Should the Committee decide that the previously submitted information is essential to the exercise of its oversight responsibilities in this area, it would require an affirmative vote of the Committee to do so. We would not, of course, take such action without notifying you in advance.

With best wishes,

Sincerely,

William J. Van Ness
Chief Counsel

WVN:bmg

AtlanticRichfieldCompany

1025 Connecticut Avenue, N.W.
Washington, D.C. 20036
Telephone 202 457 6210

Hollis M. Dole
Washington Representative

September 21, 1976

William J. Van Ness, Esq.
Chief Counsel
Committee on Interior and Insular Affairs
United States Senate
3204 Dirksen Senate Office Building
Washington, D.C. 20510

ATTENTION: Ms. Betsy Moler

Dear Mr. Van Ness:

This will acknowledge your request that Atlantic Richfield Company clarify the specific aspects of its response to the questionnaire on North Slope crude which are to be considered confidential and the reasons therefor.

In preparing its answers, Atlantic Richfield Company was not aware that the Committees on Interior and Insular Affairs and Commerce contemplated publication of the responses. Our desire was to provide those Committees with the most accurate and complete answers possible which included projections we consider to be proprietary and sensitive to public disclosure.

Specifically, the data contained in response to Questions I-A2(b) and III-A,B are projections inclusive of our best efforts to evaluate potential crude reserves not yet discovered and future crude oil supply; together they form the basis upon which significant business decisions may be made. Hence, they reflect both proprietary analyses and assumptions sensitive to competition in that they could afford other petroleum companies insight into future business decisions of Atlantic Richfield Company.

Since disclosure of the data in response to Questions I-A2(b) and III-A,B could put Atlantic Richfield Company at a competitive disadvantage in future bidding procedures and marketing decisions, we continue to believe that the data are and should remain confidential in their individual, discrete form.

We would not however, object to the inclusion of those data in any publication of composite data in which the specific estimates or assumptions of Atlantic Richfield Company were not identifiable. Nor do we object to their use within the respective Committees for their deliberations.

Our attorney reviewing the response concedes that his advice to mark the entire answer as confidential in nature, because virtually every question asked for projections or other proprietary planning information, may have been overly cautious. Upon learning of the Committee's desire to make the information public, we have reviewed each question and answer in that light. Please now be advised that Atlantic Richfield Company authorizes the public disclosure of all of its September 17, 1976 response to the questionnaire on the "Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope" except for those portions of answers to Questions I-A2(b) and III-A, B which have been deleted from the attached pages.

I trust this reply satisfies your concerns. If you should have any questions, please feel free to contact me.

Very truly yours,

Hollis M. Dole

Attachment

cc: S. Lynn Sutcliffe, Esq.
General Counsel
Committee on Commerce

AtlanticRichfieldCompany

1025 Connecticut Avenue, N.W.
Washington, D.C. 20036
Telephone 202 457 6210

Hollis M. Dole
Washington Representative

September 17, 1976

Honorable Henry M. Jackson
United States Senate
Washington, D. C. 20510

Dear Senator Jackson:

Enclosed is Atlantic Richfield Company's response to the questionnaire entitled "Potential Problems Associated with the Delivery of Crude Oil from Alaska's North Slope." By means of identical letters, Senators Warren G. Magnuson and Adlai E. Stevenson are receiving the same material. While we apologize for our failure to meet your deadline for transmittal, the importance of the subject matter prompted us to take the time required to provide you with a response that is as meaningful and accurate as possible, recognizing that projections of future supply and demand are difficult under any circumstances to forecast. As our response indicates, there is an extreme degree of uncertainty involved in projecting PADD V crude oil avails for other domestic markets.

As the discoverer of the Prudhoe Bay reserves, Atlantic Richfield Company has been aggressively working to bring this national resource to the American public. These efforts include:

- Development of the Prudhoe Bay Field

  To date, 113 developmental wells have been drilled in preparation for mid 1977 start-up.

- Participation in the Construction of the Trans-Alaska Pipeline and Related Terminal and Port Facilities

  In addition to the building of the pipeline, investments have been made to expand our terminal facilities in Long Beach, California near our Carson Refinery.

- Construction of a 100,000 B/D Refinery for North Slope Crude

  Subsequent to the North Slope discovery, Atlantic Richfield Company constructed a totally new 100 MB/D refinery at Bellingham, Washington specifically designed to process North Slope crude oil. In addition, the Company modified its existing refinery in Carson, California to maximize its capability to run North Slope crude.

- Construction of U.S. Flag Tankers

  We have built, or are in the process of building, a total of seven vessels, specifically to transport Alaskan crude to the lower 48 states.

To date, Atlantic Richfield Company has spent more than $2.2 billion for these projects, and at their completion, it is anticipated that the total cost will be more than $4.7 billion. To give some perspective on this dollar amount, it may interest you to know that this figure represents about 13.5 times our net income for 1975.

We hope you will find our response useful as you continue your studies related to potential avails of PADD V crude for other domestic markets.

Sincerely,

Hollis M. Dole

Hollis M. Dole

Enclosure

CONTAINS CONFIDENTIAL INFORMATION

ATLANTIC RICHFIELD COMPANY

RESPONSES TO QUESTIONNAIRE

"POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE"

Q. I-A1(a)

What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the trans-Alaska pipeline?

A. I-A1(a)

Alyeska's current pipeline schedule calls for deliveries of crude oil to the pipeline to commence in mid-1977. Atlantic Richfield Company has no reason to disagree with Alyeska's statement.

Q. I-A1(b)

To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

A. I-A1(b)

Alyeska management indicates that the current remedial welding program will not delay the mid-1977 scheduled completion date of the pipeline. No other technical delays are anticipated. Again, Atlantic Richfield Company has no disagreement with Alyeska's statement.

Q. I-A1(c)

What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

A. I-A1(c)

Pipeline deliveries are scheduled to commence from the Prudhoe Bay Field at a rate of 600 thousand barrels per day (MB/D) and increase until a level of 1.2 million barrels per day (MMB/D) is reached by the end of 1977 or early 1978.

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A. I-A1(c) Cont'd.

With the successful completion of the 1976 sea lift operation, we foresee no major problems which would prevent the Prudhoe Bay Field from meeting this pipeline delivery schedule. Well completions and facility startup are programmed to coincide with the Alyeska schedule. The present plan calls for expanded development during 1978 and 1979, when pipeline capacity will be available to sustain an off-take of 1.5 or 1.6 MMB/D, which we project to sustain through 1985.

These projections, based solely on Prudhoe Bay proven reserves, do not take into account future production from other potential reserves on the North Slope.

Million Barrels/Day

YEAR	PRUDHOE BAY	YEAR	PRUDHOE BAY
1977 *	0.6	1981	1.6
1978	1.2	1982	1.6
1979	1.4	1983	1.6
1980	1.5	1984	1.6
		1985	1.6

Q. I-A2(a)

What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PADD V)?

A. I-A2(a)

The current production of crude oil including lease condensate as reported by the United States Bureau of Mines (USBM) for the first four months of 1976 is as follows:

	AVERAGE DAILY RATE 1,000 BARRELS/DAY
ALASKA	183
ARIZONA	2
CALIFORNIA	876
NEVADA	NIL
	1,061

* Scheduled rate of deliveries when TAPS commences operations projected for the Fall of 1977.

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Q. I-A2(b)

What are your best current projections of production of crude oil in PADD V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

A. I-A2(b)

Estimates of future PADD V production involve a large degree of uncertainty because a major portion of the remaining untested OCS basins lie in PADD V. The table below assumes the Gulf of Alaska and offshore California will be productive and development will proceed without any unusual delays.

Million Barrels/Day

YEAR	PADD V OTHER THAN PRUDHOE BAY	YEAR	PADD V OTHER THAN PRUDHOE BAY
Current	1.1	1981	1.0
1977	1.0	1982	1.0
1978	1.0	1983	1.1
1979	1.0	1984	1.4
1980	0.9	1985	1.6

Q. I-A3(a)

What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content).

A. I-A3(a)

Atlantic Richfield Company has no specific knowledge other than that publicly available. The USBM provides such information.

Q. I-A3(b)

What are your best current projections of crude oil and product imports into PADD V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in Question IV-A.)

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A. I-A3(b)

Atlantic Richfield has no way of knowing what others' plans may be for importation of foreign crude oil after the Trans-Alaska Pipeline System (TAPS) is operational.

Atlantic Richfield Company will cease importation of intermediate and high sulfur foreign crudes, and a significant fraction of the low sulfur foreign crude into PADD V as soon as sufficient North Slope crude is available.

Importation of crude oil into PADD V may well be dramatically affected by the start-up of TAPS. Depending upon each refiner's particular internal economics and processing capabilities, we would anticipate that when pipeline operations reach projected rates, the intermediate sulfur North Slope crude will replace virtually all intermediate and high sulfur foreign crudes currently imported into PADD V.

Q. I-B1

What is the current refinery capacity and throughput in PADD V?

A. I-B1

API reports that current PADD V refining capacity is approximately 2.7 MMB/D, and that crude runs are currently at 2.2 MMB/D.

Q. I-B2

What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

A. I-B2

The FEA estimates that for 1978 and beyond, refinery capacity will level out at 2.9 MMB/D.

Comments on long-term refining capacity can only be speculative since demand growth patterns must be the major incentive for such expansion. Based on today's refinery crude input of 2.2 MMB/D, refinery capacity in PADD V should be sufficient to handle a 3 percent compounded growth rate until about 1983 or 1984. A 4 percent compounded growth rate would strain refinery capacity 1-2 years earlier.

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Q. I-B3

What part of the current and projected PADD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

A. I-B3

Atlantic Richfield Company has no information regarding the ability of competitors to handle North Slope crude other than what has been published. (See Oil and Gas Journal, March 1, 1976, pp. 55-58) We can comment that in the late 1960's our company embarked on the construction of a new refinery in the Pacific Northwest designed specifically to process North Slope crude. This refinery near Bellingham, Washington can process about 97 MB/D of crude. At our Carson, California facility, the capacity for North Slope crude is 100 MB/D out of a total capacity approaching 185 MB/D. Atlantic Richfield Company expects to process about 197 MB/D of North Slope crude.

N.B. The numbers used in I-B1, 2 and 3 are based upon current known product specifications and government regulations. More restrictive changes in regulations governing fuel sulfur levels, fuel nitrogen levels, gasoline lead content, gasoline vapor pressure, stationary source emissions, or other environmental or product quality factors could have a significant impact on the refining industry's ability both to process North Slope or any other intermediate or high sulfur crude and to meet market demands for specific products.

Q. II-A

What is the current demand for crude oil and refined petroleum products in PADD V?

A. II-A

As previously answered, current refinery runs of crude in PADD V are 2.2 MMB/D.

Atlantic Richfield Company's estimate of total current demand for petroleum products in PADD V is 2.4 - 2.5 MMB/D. The difference between crude input and petroleum product demand relates to processing gains, natural gas liquids, and product imports.

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Q. II-B

What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

A. II-B

Forecasts of demand for petroleum products in future years are very speculative. Government actions on price levels, consumer reaction to the conservation ethic, availability of alternative energy sources such as coal, hydro, and nuclear, and the availability of natural gas all have major influences on petroleum demand. We estimate that the annual growth rate will be between 3 and 5 percent.

Q. III-A

(Assuming that none of the measures identified in Question IV-A is implemented:)

What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V (i.e., the difference between total PADD V production and refinery runs plus addition to stocks)?

A. III-A

Our most recent projections of the West Coast crude oil avails for other markets and the basic assumptions used to derive those values are shown in the following chart:

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A. III-A,B

WEST COAST CRUDE AVAILABLE FOR OTHER MARKETS
THOUSANDS OF BARRELS/DAY
( ) = Deficiency

	1978	1979	1980	1981	1982	1983	1984	1985
HIGH CASE	400	400	400	500	700	1100	1500	2000
LOW CASE	200	--	--	--	(200)	(400)	(500)	(700)
"BEST GUESS"	400	400	400	400	550	600	650	700

High Case Assumptions

1. TAPS expansion to 1600 MB/D by mid 1979, increasing to 2000 MB/D by 1984.
2. Maximum TAPS throughput of 2000 MB/D
*3. New South Alaska and California OCS production of 1500 MB/D by 1985
4. All North Slope NGL available to PADD V beginning in 1983
5. Continued low sulphur imports of 400 MB/D
6. Average annual demand growth of approximately 3%

Low Case Assumptions

1. Maximum TAPS throughput of 1600 MB/D reached in mid-1980
*2. No new Southern Alaska OCS production
3. No Alaska NGL into PADD V
4. New California OCS production of 300 MB/D by 1985
5. Continued low sulfur imports of 400 MB/D
6. Average demand growth of approximately 5% resulting from:
   a. Increased basic petroleum demand
   b. 25% decline in natural gas supplies by 1985
   c. Lower expansion of coal and geothermal than assumed in high case

"Best Guess" Assumptions

1. TAPS expansion to maximum capacity of 1600 MB/D by mid-1979

*2. New South Alaska and California OCS production of 1000 MB/D by 1985 50% of new south Alaskan assumed to be low sulfur crude.

   Replacement by 1985 of imported low sulfur crude by new South Alaska low sulfur crude.

4. No Alaska NGL into PADD V
5. Average annual demand growth of approximately 3%

CONTAINS CONFIDENTIAL INFORMATION

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* The South Alaska OCS basins constitute among the largest, but most uncertain components of potential PADD V crude reserves. It is uncertain if the area will be productive, and if so, to what extent. Moreover, it is unknown if any such reserves would be high or low sulfur. If this area is productive, only very large fields are likely to be economic because of the extreme environmental conditions. The cases shown do not reflect the full range of uncertainty. Rather, they indicate reasonable possibilities. Much of the uncertainty will remain unresolved until results of the first few exploratory wells are available.

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Q. III-B

What are your best current estimates of the PADD V surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PADD V production and refinery runs plus additions to stocks of such crude oil)?

A. III-B

Atlantic Richfield has no basis upon which an estimate could be made as to what part of any crude avails over PADD V demand would be comprised of North Slope or similar grades of crude oil.

SECTION IV

"PROPOSED RESPONSES TO THE PROJECTED WEST COAST SURPLUS"

Q. IV.A

Alternatives (1), (2), (3), (4) and (7):

A. IV.A

As to alternatives 1, 2, 3, 4, and 7 (Kitimat, Northern Tier, Sohio, and Isthmus pipelines and a desulphurization facility), we do not feel that our studies have progressed to a point to which we could make a meaningful comment.

Q. IV.A

Alternative (5):

Use of small tankers through the Panama Canal or VLCCs around Cape Horn to the U.S. Gulf Coast.

Due to physical restrictions of the Canal and the limited availability of smaller vessels, we estimate that potential movements through the Panama Canal would be limited to about 200 MB/D.

For shipments around Cape Horn, our analyses indicate that sufficient tonnage is available for shipments of 200 to 300 MB/D of crude to the Gulf Coast.

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Q. IV-A

Alternative (6):

Retrofitting existing District V and/or Northern Tier refineries to run North Slope or comparable grades of crude oil.

A. IV-A6

The costs of converting an existing refinery for processing North Slope crude are substantial and vary significantly among refineries. The size, configuration, metallurgy, and product output of a refinery all contribute to the ultimate cost. Existing and future environmental regulations may inhibit retrofitting to utilize higher sulfur crude in PADD V.

Q. IV-A

Alternative (8):

Shutting-in of producing capacity in the field and/or postponement of the increases in pipeline capacity on a short term basis (pending increases in PADD V crude oil demand to absorb the surplus).

A. IV-A8

Given the serious balance of payments burden caused by the purchase of foreign crude, and the need to reduce the Nation's dependence on insecure sources of crude oil, we suggest that the shutting-in of domestic production is not in the best interests of the Nation.

Q. IV-A

Alternative (9):

Exports or exchanges with Canada, Japan, or other countries either on a short term basis (pending implementation of one or more of the foregoing systems) or on a long-term basis (pending increases in PADD V crude oil demand to absorb the surplus).

A. IV-A9

The export of crude to Canada, Japan, or other foreign countries in exchange for foreign source crudes represents a mechanism by which North Slope crude could be utilized in the short term. The lead time involved would be minimal.

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Q. IV-B:

Evaluation and comparison of alternatives.

A. IV-B:

The alternatives described are in the preliminary stages of analysis. At this time, Atlantic Richfield Company is unable to make any meaningful evaluation or comparison of their relative merits.

Q. IV-C:

"Implementation"

A. IV-C:

As indicated above, Atlantic Richfield Company has not yet concluded which alternative may be most desirable. In addition, despite our "best guess" as to the amount by which PADD V production might exceed demand, that amount and its duration cannot be quantified with sufficient specificity to determine which alternative would be preferred.

In general, however, it may be useful to recognize that:

1. Depending on the level of avails, there may be a need for implementing more than one alternative. For example, in cases ranging around the "Low Case" (in the answer to III A) only low capital investment solutions like foreign exchange or tanker runs or some use of existing pipeline "hardware" would be viable.

2. Further, if cases like the "High Case" or "Best Guess" case (in the answer to III A) eventually occur, high capital cost new trans-U.S. pipeline systems will be justified. This situation, if it occurred, would not become evident until some of the PADD V key exploration programs develop information. In particular, the Gulf of Alaska and the current California OCS exploration should be watched for early indications to resolve this outlook.

Q. IV-D1

If none of the pipeline systems listed in IV-A, 1-3 (Kitimat, Northern Tier, and Sohio) is approved and constructed in time to transport any of the anticipated West Coast surplus in

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PADD V created by North Slope crude oil production, how would you recommend the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV-A, 4-9).

A. IV-D1

Of the alternatives available, the use of tankers for movements through the Panama Canal and around Cape Horn, Four Corners Pipeline, and exchanges with Canada, Japan, and other foreign countries would be effective ways of handling these avails on a short-term basis.

Assuming that the "long-term" contemplated in the question is of sufficient duration to recoup the investment, and that high enough crude oil avails develop, we would hope that a pipeline system acceptable to the public would be developed.

The choice of alternatives depends on the volume and duration of the crude available for other markets. If the volumes and/or duration in question were limited, use of existing marine vessels or other non-capital alternatives would be preferred. If the volumes of crude oil to be moved were substantial, and were expected to be shipped to a relatively permanent market, a capital intensive pipeline system could become most practical.

Q. IV-D2

What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?

A. IV-D2

Atlantic Richfield has no policy objections to exports as a temporary solution, so long as they are coupled with exchange arrangements so that there is no loss of domestic crude availability in the United States as provided in the TAPS enabling legislation.

Those individuals who have voiced policy objections to an export/exchange apparently fear supply insecurity during an embargo and are concerned lest the oil companies use the

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export/exchange mechanism to avoid Federal price controls. Both objections are baseless. The reasons are simple. During an embargo, deliveries of North Slope oil that would have gone to a foreign country in an exchange would be available for transport instead (in the excess tankers idled by the embargo) to the East Coast. The second objection is also invalid. Current price regulations do not permit circumvention, and no price control system can be envisioned which would permit such a result by operation of exchange agreements.

Q. IV-D3(a)(b)

Is there a need for Federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PADD V?

What, if any, constraints should such legislation address?

A. IV-D3(a)(b)

We find ourselves in an environment where it is increasingly difficult to plan and construct energy related facilities. One reason for this is the lack of a mechanism to resolve, in a timely fashion, the conflicts between two national goals, environmental protection and energy resource development.

Given the environmental opposition to a trans-United States pipeline system in the West Coast states, and apparent threats by some California officials to withhold permits, it would appear that special legislation may be required. Because of the substantial impediments to the authorization and construction of a pipeline and related facilities, it may be unlikely that a pipeline can be constructed without the type of legislation that enabled the building of the Trans-Alaska Pipeline System.

Q. V-A

What is the full anticipated cost of constructing and equipping the Trans-Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?

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A. V-A

The currently projected costs of constructing and equipping TAPS and the Valdez terminal facilities are:

Pipeline and Terminal (Capacity)*	Estimated Cost **
	($ millions)
1.2 MMB/D	7700
1.6 MMB/D	8325

During construction, each participant carries its own interest costs. The cost of money to each participant varies, depending upon extent of internally generated funds, credit ratings, and timing and types of financings. Interest costs of other participants are unknown to Atlantic Richfield.

Q. V-B

What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985? (Specify throughput assumptions.) What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?

A. V-B

Tariffs will be established by the Interstate Commerce Commission (I.C.C.). I.C.C. rules limit rate of return to 7 per cent of the I.C.C. valuation of the carrier's property.

I.C.C. valuation guidelines for existing pipelines are largely inapplicable to the proper valuation of TAPS due to its unique construction requirements, Arctic operating conditions, and strict environmental requirements. Moreover, the final construction costs for TAPS are not yet known. Consequently, it is not possible to determine the I.C.C. valuation of TAPS, so no definitive tariff estimates are possible.

Q. V-C

To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act,

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* No current cost projections have been made for capacities in excess of 1.6 MMB/D.

** Cost estimates exclude interest expense during construction.

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or (b) at the upper tier price established by FEA, be expected to constrain West Coast refinery prices? Refinery prices East of the Rockies.

A. V-C

The landed cost of alternative (foreign) crude oil would determine the landed value of North Slope crude. For example, the competitive landed cost at Los Angeles, less transportation expenses, would be a determinant of the well-head price of Prudhoe Bay crude oil. While it is not possible to definitively predict the transportation tariffs, current comparable costs for foreign crude oil would constrain Prudhoe Bay crude prices to less than the current upper tier prices. Consequently, competition would constrain product prices. Therefore, imposition of ceiling prices on North Slope crude would not be necessary or desirable. That situation is expected to continue for the foreseeable future.

Because of the uncertainty of transportation expenses from the North Slope, it is not possible to assess the effect a limitation to the composite price of the EPCA would have on product prices. However, current regulations would not impose such a limit, and if that limit were less than the competitive value of North Slope crude, its imposition would be grossly inequitable.

With respect to the effect price limits on North Slope crude would have on East Coast product prices, it is axiomatic that the greater expense of transporting North Slope crude to the East Coast, and the relatively less expensive cost of transporting foreign crude to those ports, would result in downward competitive pressure on North Slope well-head prices. Thus, again, there would be no necessity of imposing well-head price limits to constrain product prices.

Q. V-D

If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g., imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?

A. V-D

We do not expect the establishment of multiple well-head prices for North Slope crude.

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Q. V-E

To what extent, if at all, would the alternative measures identified in Question IV-A affect average prices of North Slope and similar grade crude oil produced in PADD V (a) at the wellhead, (b) at West Coast refineries, and (c) at refineries east of the Rockies?

A. V-E

Assuming a free market, West Coast crude will compete with alternative source crude on a landed cost basis.

As the capital costs of those respective alternatives increase, the transportation costs would increase. One would expect a corresponding downward pressure on the well-head prices of West Coast crude.

There are simply too many major unknowns to be able to quantify the extent to which any of the alternatives in Q. IV-B would affect West Coast well-head prices.

WILLIAM A. WEST
Executive Assistant to
the Chairman of the Board

August 25, 1976

Re: Questionnaire on Alaska North Slope Crude Oil

Ms. Betsy Moler
Committee on Interior and
Insular Affairs
U. S. Senate
Washington, D.C. 20510

Dear Ms. Moler:

Thank you for your letter of August 23, 1976 to Mr. C. C. Garvin, Jr. with which you enclosed a questionnaire on the Alaskan North Slope Crude Oil. We have passed this letter on to our Exxon Company U.S.A. headquarters in Houston who are responsible for domestic planning matters of this kind.

They will be in touch with you directly with any questions they have.

Sincerely,

William West

WAW:def
cc: Mr. Steven Flajser

EXXON COMPANY, U.S.A.
POST OFFICE BOX 2180 - HOUSTON, TEXAS 77001

RANDALL MEYER
PRESIDENT

September 17, 1976

The Honorable Warren G. Magnuson
The Honorable Henry M. Jackson
The Honorable Adlai E. Stevenson
Chairmen of the Senate Committees on
Interior and Insular Affairs and
Commerce and Subcommittee on
Oil & Gas Production and Distribution
The United States Senate
Washington, D. C. 20510

Dear Senators Magnuson, Jackson, and Stevenson:

The attached information is in response to your inquiry of August 23, 1976 regarding PAD District V oil. Certain of the questions call for estimates or projections of future petroleum supply, demand, or operations from a total industry standpoint. I am sure you will appreciate that it is not possible to make precise forecasts in these areas. We have based our replies on our current estimates of these factors.

The best long-range solution to the potential PAD V surplus is modification of PAD V refineries to enable them to process North Slope type crude, together with the timely completion of one or more major West to East pipelines. From a national security standpoint, the pipelines will provide a secure, high-capacity means of moving domestic oil between PAD V and PAD I-IV, which should be particularly valuable in the event of supply curtailments or a national emergency. Short range we feel there are only two possible alternatives: (1) tanker movement to the U.S. Gulf/East Coast, and (2) exchanges with refiners in noncontiguous foreign countries. Movement by tanker to the U.S. Gulf/East Coast would directly replace imports while the exchanges would have essentially the same balance of payments effects.

There does not appear to be any need for federal legislative action at this time regarding the transportation of North Slope crude. However, a number of governmental actions would be timely; e.g., (1) prompt removal of the federal price controls which discourage investments to adapt refineries so that they can process North Slope quality crude oil, (2) a prompt determination of whether the findings required by the TAPS Act to authorize the exchange of North Slope crude oil with refiners in noncontiguous foreign countries are warranted, (3) efforts by federal, state and local governments to expedite the necessary hearing and permitting processes for proposed West to East pipelines, and (4) Maritime Administration approval for the temporary use in U.S. coastwise service, if needed, of certain U.S. flag vessels currently in foreign service.

As you know, Exxon believes that production of the North Slope oil will be very important to the United States in alleviating the energy supply problem over the next decade. We appreciate the opportunity to comment on these matters.

Sincerely,

Randall Meyer

RM:pf
Attachment

POTENTIAL PROBLEMS ASSOCIATED WITH THE DELIVERY OF CRUDE OIL FROM ALASKA'S NORTH SLOPE

I. West Coast Petroleum Supply

A. Crude Oil

1. Alaska

a. What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska pipeline?

- The Trans-Alaska pipeline system is scheduled for mechanical completion in mid-1977. Start-up and pipeline and terminal fill should enable shipment of North Slope crude from Valdez in the third quarter of 1977.

b. To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

- It is anticipated that satisfactory resolution of welds and other known technical questions will not materially alter the present schedule.

c. What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

- Exxon's current estimate of industry production and deliveries from Valdez of North Slope crude oil - MMB/D (millions of barrels per day).

4th Qtr 1977	1978	1979	1980	1981	1982	1983	1984	1985
0.6	1.2	1.2	1.5	1.5	1.5	-*	-*	-*

Note: These estimates assume an intermediate TAPS throughput capacity of 1.2 MMB/D in 1978, 1.6 MMB/D in 1980, and an ultimate capacity of 2.0 MMB/D. The 2.0 MMB/D capacity would be needed only if additional new discoveries are made in the area tributary to the pipeline.

*For 1983-1985 estimates see I-A.2.b.

2. West Coast Production

a. What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PAD V)?

- PAD V current crude and condensate production - MB/D February 1976 - 1,074 MB/D.

Source: Mineral Industry Surveys, Department of Interior, Bureau of Mines, Petroleum Statement, Monthly, Prepared July 14, 1976, Table 3, Page 7.

b. What are your best current projections of production of crude oil in PAD V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

- Exxon's estimate of industry's PAD V crude and condensate production - MMB/D.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Ex North Slope	1.2	1.1	1.2	1.2	1.2	1.3	-	-	-
Total PAD V	1.3	2.3	2.4	2.7	2.7	2.8	3.2	3.5	4.1

Note: Subsequent to 1982 these estimates include a substantial volume of crude from yet to be discovered reserves and must be viewed as speculative. Consequently, estimates of production for 1983-1985 are reported on a total PAD V basis only.

3. Imports

a. What is the current level of crude oil and product imports into PAD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content.)

- The information on the current level of crude oil and product imports into PAD V by country of origin can be found in Tables 14, 15 and 16 of the data source referred to in I-A, 2, a) above. Copies attached: See Attachment A.

- Exxon does not have access to information indicating the sulfur content of crude imported by other PAD V refiners. However, based on the referenced data source above, it is estimated that a minimum of 65% of the crude imports for February (Table 14) are from countries which are known to produce low sulfur content crudes. For example, out of total imports of 22,816 MB, Indonesia which produces primarily low sulfur crude oil was the source for 10,439 MB, or about 46% of the total.

b. What are your best current projections of crude oil and product imports into PAD V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in question IV-A.)

- Exxon's estimate of industry foreign imports into PAD V - MMB/D.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Products	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0
Crude	0.8	0.6	0.5	0.6	0.5	0.5	0.4	0.3	0

- We are unable to predict with any reasonable degree of confidence the country of origin for products or crude imports. However, we believe the majority of the crude will be low sulfur.

- Our projections indicate that product imports into PAD V will remain at approximately the current level through the early 1980's, with essentially the same product mix, and then be phased out as refiners have an incentive to construct domestic refinery capacity to supply that segment of the demand.

- The primary assumption in the development of these projections is that there will be no significant change in existing West Coast refining capability to process heavier sour crudes before the mid-1980's.

- For years now federal government price controls, which do not allow complete recovery of additional operating and/or capital costs, have discouraged such investments and continue to do so. Consequently, we anticipate that imports of low sulfur crude oil into PAD V will remain at about 500+ MB/D until the early 1980's--because there has been little indication in the trade literature that refiners currently processing light, low sulfur crude are constructing facilities to enable them to replace low sulfur crude with North Slope crude.

B. Refinery Capacity

1. What is the current refinery capacity and throughput in PAD V?

- Current PAD V refinery capacity, January 1, 1976 - MB/D Operating - 2,305.

Source: Mineral Industry Survey, U.S. Department of Interior, Bureau of Mines, Petroleum Refineries, Annual, Prepared July 14, 1976.

- Current PAD V throughput, February, 1976 - MB/D.

Crude Domestic	1,059
Foreign	853
Total Crude Runs	1,912
Unfinished	30
Total Crude & Unfinished	1,942
Natural Gas Liquids	51
Other Hydrocarbons	9
Total Input (throughput)	2,002

Source: Mineral Industry Survey, U.S. Department of Interior, Bureau of Mines, Petroleum Refineries, Petroleum Products and NGL for February, 1976.

2. What are your best current projections for refining capacity and throughput in PAD V for each year through 1985?

- The following Exxon estimate of PAD V industry average, annual pipestill capacity is on the same basis as the historical data reported to the Bureau of Mines.

MMB/D

1977	1978	1979	1980	1981	1982	1983	1984	1985
2.8	2.8	2.9	2.9	2.9	2.9	3.2	3.4	3.5

This outlook projects no significant new refinery construction in PAD V beyond that already in progress until the mid-1980's.

Sustainable usable crude capacity is normally estimated to be about 90% of reported total pipestill capacity because of demand seasonality, equipment downtime, and refinery runs of unfinished and natural gas liquids which utilize pipestill capacity. Exxon's projection of industry usable refining capacity in PAD V based on announced expansions and nominal debottlenecking is as follows (MMB/D):

1977	1978	1979	1980	1981	1982	1983	1984	1985
2.5	2.6	2.6	2.6	2.6	2.7	2.9	3.1	3.2

Given this capacity outlook, a reasonable estimate of PAD V crude runs would be as follows:

1977	1978	1979	1980	1981	1982	1983	1984	1985
2.1	2.3	2.4	2.6	2.6	2.7	2.8	2.9	3.1

3. What part of the current and projected PAD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

   - Exxon's Benicia, California refinery is capable of running 100% North Slope crude.

   - We do not have access to the details of facilities of other West Coast refiners, their crude slates or product sales mix by refinery.

   - However, based on available data and historical trends, it appears that 0.5-0.8 MMB/D of low sulfur crudes will be required after North Slope crude is available because some PAD V refineries have not been adapted to run higher sulfur domestic crudes, such as North Slope crude in place of the low sulfur imports. We can see no indication in trade literature that other West Coast refiners are currently undertaking retrofitting their refineries to run additional high sulfur crude in the future. Even once initiated, such retrofitting normally requires about 3 years to accomplish (assuming no major environmental or other permitting delays), thus making the early 1980's the earliest likely date that all foreign low sulfur imports could be replaced with North Slope crude. Current FEA regulations discourage such investments.

II. West Coast Petroleum Demand

A. What is the current demand for crude oil and refined petroleum products in PAD V?

   - Current demand for PAD V crude oil and refined products - MB/D.

February, 1976	
Crude Oil	Refined Products (Domestic Demand)
1,912	2,086

Source: Mineral Industry Surveys, Department of Interior, Bureau of Mines, District V Petroleum Statement, Monthly, Prepared July 8, 1976.

B. What are your best current projections for crude oil and refined petroleum product demand in PAD V for each year through 1985?

   - Our current estimate of future PAD V industry crude and refined petroleum products demand - MMB/D.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Crude	2.1	2.3	2.4	2.6	2.6	2.7	2.8	2.9	3.1
Refined Products (Domestic Demand)	2.4	2.6	2.8	2.9	3.0	3.0	3.1	3.2	3.3

- The difference between refined products and crude demands is made up by product imports, interdistrict movements, NGL and refinery volumetric gains.

III. West Coast Surplus

Assuming that none of the measures identified in question IV-A is implemented:

A. What are your best current estimates of the PAD V net surplus or deficit of crude oil for each year through 1985 in PAD V (i.e., the difference between total PAD V production and refinery runs plus addition to stocks)?

- Estimated industry PAD V crude surplus in MMB/D.

	4th Qtr 1977	1978	1979	1980	1981	1982	1983	1984	1985
Surplus	0.2	0.6	0.5	0.7	0.6	0.6	0.8	0.9	1.0

- It should be noted that the surplus continues throughout the period, indicating the continuing need for facilities to move this surplus. Also, it is emphasized that the estimates include production from oil reserves yet to be discovered, as well as the continuation of low sulfur crude imports mentioned in I-B, 3.

B. What are your best current estimates of the PAD V surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PAD V production and refinery runs plus additions to stocks of such crude oil)?

- We are not able to project the specific crudes that will be moved off the West Coast; however, we believe that in the near term the surplus will be a crude with greater than 0.5% wt. sulfur.

IV. Proposed Responses to the Projected West Coast Surplus

A. Proposed responses to deal with the projected surplus of North Slope grades of crude oil on the West Coast have included one or a combination of the following:

1. Construction of the proposed Trans-Provincial pipeline from Kitimat, British Columbia connecting with the Interprovincial pipeline at Edmonton.

2. Construction of the proposed Northern Tier pipeline from Port Angeles, Washington to Clearbrook, Minnesota.

3. The proposed Sohio project to convert and reverse an existing El Paso Natural Gas pipeline and build necessary connecting pipelines from Long Beach, California to Midland, Texas.

4. Construction of a pipeline across the Isthmus of Panama or across Guatemala to connect tanker routes from Alaska with tanker routes to the U.S. Gulf Coast.

5. Use of small tankers through the Panama Canal or VLCCs around Cape Horn to the U.S. Gulf Coast.

6. Retrofitting existing PAD V and/or Northern Tier refineries to run North Slope or comparable grades of crude oil.

7. Construction of one or more facilities (at Valdez, Kitimat, Port Angeles or elsewhere) to desulfurize and raise the gravity of North Slope crude oil in order to use it in existing West Coast and/or Northern Tier refineries.

8. Shutting in of producing capacity in the field and/or postponement of the increases in pipeline capacity on a short-term basis (pending increases in PAD V crude oil demand to absorb the surplus).

9. Exports or exchanges with Canada, Japan or other countries either on a short-term basis (pending implementation of one or more of the foregoing systems) or on a long-term basis (pending increases in PAD V crude oil demand to absorb the surplus).

B. If you have knowledge of these proposals, evaluate and compare with the foregoing responses and any other relevant alternatives with respect to:

1. The current status of each project or proposal:

- Alternates 1, 2, 3, 4: Exxon is not presently a direct participant of any of the proposed pipeline projects. However, we are following progress very closely. For example, we are currently conducting a technical study of the Sohio pipeline project. Imperial Oil Limited--a Canadian affiliate--has an indirect interest in the Kitimat proposal through its partial ownership of the Trans-Mountain and Interprovincial pipelines.

- Alternate 5: For the first several years after TAPS start-up, Exxon expects to have tanker capacity available to move its North Slope crude that cannot be sold in PAD V through the Panama Canal to the U.S. Gulf/East Coast. As soon as they can be made available, West to East pipelines offer a more economical means of transporting the crude.

- Alternate 6: Exxon's Benicia refinery is capable of running all North Slope or similar type crudes. As indicated in our answer to I., B., 3., we can see little evidence of major retrofitting investments being made at West Coast refineries to run additional North Slope or similar type crudes.

- Alternate 7: Preliminary analysis to date indicates that technical and economic considerations are likely to make this alternative impracticable.

- Alternate 8: Shutting in North Slope crude does increase U.S. dependency on foreign crude sources versus North Slope production at field or pipeline capacity. Shutting in does not make efficient use of capital already spent and discourages exploration and development of new reserves. With proper government action and reasonable economic conditions, this alternative should not have to be utilized. Exxon is proceeding with plans to fully develop the Prudhoe Bay reserves and plans to continue exploration in Alaska including the offshore. These plans are being developed assuming that the FEA will establish a North Slope ceiling price that will encourage further arctic development. The U.S. will need this crude for greater energy self-sufficiency.

- Alternate 9: Even though exchanges with noncontiguous foreign states may provide a cheaper transportation alternative, they require particular Presidential findings, which are subject to disapproval by Congress within a specified time period. Exchanges with contiguous foreign states are conditionally permitted under the provisions of the TAPS Authorization Act. However, such exchanges have restrictive physical limitations because of the number and location of Mexican and Canadian refineries that can run North Slope crude.

2. The estimated time for approval and implementation, including a description of:

   - Alternates 1, 2, 3 and 4: Can best be answered by the direct participants in these pipelines.

- Alternate 5: To ensure adequate tanker capacity to move the projected industry PAD V crude to the U.S. Gulf/East Coast will probably require that the Maritime Administration grant permission for some U.S. flag ships presently in foreign trade to operate temporarily in domestic service. It should be possible for the authorization to be processed prior to the expected start-up of TAPS.

- Alternate 6: Must be determined from individual refinery owners.

- Alternate 7: Refer to answer IV-B.1, "Alternate 7."

- Alternate 8: Refer to answer IV-B.1, "Alternate 8."

- Alternate 9: Refer to answer IV-B.1, "Alternate 9."

3. Direct capital and operating costs.

- Alternates 1, 2, 3, 4: Can best be answered by direct participants.

- Alternate 5: Capital and operating costs should approximate today's levels adjusted for inflation and market conditions.

- Alternate 6: Exxon's Benicia Refinery is now equipped to process North Slope or similar crudes. Operating costs would approximate today's rates adjusted for inflation.

- Alternate 7: Refer to answer IV-B.1, "Alternate 7."

- Alternate 8: Refer to answer IV-B.1, "Alternate 8."

- Alternate 9: Providing shorter, total transportation distance is involved in an exchange, this should be less costly than Alternate 5. Refer to answer IV-B.1, "Alternative 9."

4. Financing arrangements.

- Alternates 1, 2, 3, and 4: Can best be answered by direct participants.

- Alternate 5: Exxon does not anticipate the need for any special financial arrangements--other than those arrangements normally used in ship construction and chartering. Other transporters should provide information on their requirements.

- Alternate 6: Exxon's Benicia refinery is now equipped to process North Slope crude. Information on financing required by other refiners should be determined from those companies.

- Alternate 7: Refer to answer IV-B.1, "Alternate 7."

- Alternates 8 and 9: Not applicable.

5. Refiner and consumer costs of crude oil nationally and by region.

   - The FEA is not required by law to make a decision on a North Slope ceiling price until April 1, 1977; in addition, there are uncertainties as to transportation costs. Estimates of crude oil costs to refiners and the interactions of crude costs are necessarily speculative and the underlying assumptions confidential from a competitive standpoint. Refer to answer V-C, D, and E.

6. Wellhead price for North Slope crude oil, cash flow to the operating companies and revenue to the State of Alaska.

   - The statement made for item 5 above applies. In addition, there are many uncertainties concerning future tax legislation and pipeline regulations.

7. Net overall national economic costs and/or benefits.

   - All of the proposed alternates--except shutting in production--improve balance of payments and lessen U.S. dependency on foreign oil. Shutting in production would make inefficient use of capital already spent and would increase dependency on foreign oil. Furthermore, it would reduce the incentive to explore and develop new reserves.

8. Promotion of the capacity for long-term domestic self-sufficiency.

   - All alternatives--except shutting in production--enhance the opportunity for long-term self-sufficiency. However, any of these alternatives must be economically justifiable in order to attract the capital required--recognizing the technical risks and regulatory uncertainties.

9. Environmental and safety impacts.

   - While we do not have detailed information on the environmental and safety aspects of all of these projects and while Environmental Impact Statements will be required for some of them, there does not appear to be any insurmountable environmental or safety problems associated with the most probable alternative.

10. Any other relevant factors.

- None.

C. Implementation.

1. a. Considering the foregoing factors which of the alternatives or combination of them currently appear on balance to be best?

- Long range: The best long range solution to the potential PAD V surplus is modification of PAD V refineries to enable them to process North Slope type crude, together with the timely completion of a West to East pipeline system or systems. From a national security standpoint, a West to East pipeline system provides a secure high-capacity connection between PAD V and PADs I-IV, which should be advantageous in the time of an emergency. The pipeline project that appears to be the most developed is the Sohio project. This project provides access to other major U.S. crude markets (the U.S. Gulf, Mid-Continent and the Midwest). Its origin terminal would also serve the largest West Coast market: Los Angeles. Also, it makes maximum use of existing facilities.

  In addition to the Sohio project, it could be advantageous to have another pipeline which will serve the Northern Tier/Midwest refiners. As has been pointed out in industry publications, not all Northern Tier refiners can process North Slope type crude.

- Short range: There are only two short range alternatives that appear possible: (1) tanker movement to the U.S. Gulf/East Coast, and (2) exchanges with refiners in noncontiguous foreign countries.

  o Refineries on the U.S. Gulf run crudes similar to North Slope crude and imports of foreign crude would be reduced if North Slope crude is processed by them. Crude oil made available in the U.S. Gulf can be moved in existing transportation facilities to Mid-Continent and Midwest markets.

  o Exchanges with refiners in a noncontiguous foreign country such as Japan, if authorized by the federal government, might be worked out through normal commercial channels in such a way that the foreign refiners would

process North Slope crude in lieu of foreign crudes which would be delivered instead to U.S. refineries. However, no such exchanges of North Slope crude with refiners in non-contiguous foreign countries are feasible until and unless a federal government finding is made that such a transaction would be in the national interest and conforms to other specified prerequisites. Exchange possibilities for North Slope crude with Canada or Mexico refiners appear very limited in the near term due both to pipeline and refinery processing limitations.

b. Which appear to be workable and acceptable?

- Alternates 1, 2, 3, 5, 6, and 9 appear workable. Whether each is "acceptable" or not is a subjective judgment that depends on the available alternates. More than one of these alternates are likely to be required.

c. Unworkable or unacceptable? Why?

- Alternates 4, 7, 8

  - o While Alternate 4 may be workable, it would seem to be relatively unattractive both from a national security and commercial standpoint. Compared to other transcontinent alternates it entails longer supply lines with a portion of the system under control of a foreign power with which the U.S. does not have both a pipeline treaty and pipeline interdependence.

  - o Alternate 7: Refer to answer IV-B.1, "Alternate 7."

  - o Alternate 8: Shutting in production was covered previously.

2. a. Among those alternatives identified as workable and acceptable which are now under active consideration by producers, refiners or others?

- Exxon is considering tanker movements to the U.S. Gulf/East Coast short range, and utilization and/or possible participation in the one or more West to East pipeline systems long range. We cannot, of course, speak for others.

b. Which have reached the stage of applications for necessary certificates, licenses or permits?

- Sohio has indicated in recent government testimony that their pipeline project has reached the application stage.

3. For each of those alternatives identified as workable or acceptable, what appear to be the most significant, critical hurdles to implementation (for example, demonstration of technical or economic feasibility; federal or state air quality standards; obtaining competent and credible corporate sponsors; throughput commitment; legal authority; financing; federal approval of required certificates, licenses or permits; foreign country, state or provincial approvals or certificates, licenses or permits)?

- Alternates 1, 2, & 3:

  - o Permits
  - o Assurance of uninterrupted flow in subsequent connecting pipelines.
  - o Marine terminal permits.
  - o FPC action (Sohio project only).

- Alternate 5 (short range only): Temporary utilization in coastal service of some U.S. flag ships currently licensed only for foreign trade.

- Alternate 6: Federal price controls discourage the capital investments required.

- Alternate 9: If refineries in noncontiguous foreign countries are involved, Presidential findings subject to disapproval by Congress are required.

- Each of the above alternates could be adversely affected by the requirements of the Clean Air Act of 1970 and subsequent amendments. The Clean Air Act amendments that have passed the Senate and are now under consideration in the House would present even more significant, critical hurdles to implementation of these alternates.

4. For each of those alternatives identified in IV-A, what is your understanding of the time frame for completion? At what capacity?

- Alternate 1: We are advised that the project developers believe that completion could be achieved in 1978 or 1979, if not unduly delayed by permitting requirements, and will have an initial capacity of 300 MB/D.

- Alternate 2: We are advised that the project developers believe that a Northern Tier pipeline having a proposed capacity of 800 MB/D might be completed sometime in the 1978-1980 time period if not unduly delayed by permitting requirements.

- Alternate 3: We are advised that Sohio expects completion late in 1978 or early 1979, if not unduly delayed by permitting requirements, and will have an initial capacity of 500 MB/D expandable to 1,000 MB/D.

- Alternate 4: The Trans-Panama Pipeline that has been discussed is reportedly proposed to have a 1,000 MB/D capacity. We have no information concerning when it could be completed were it to proceed, which seems doubtful at present.

- Alternate 5: Could be operational prior to the start-up of TAPS.

- Alternate 6: Since our refineries in PAD IV and V do not require retrofitting, this can best be determined from the companies whose refineries require adaptation investment to run North Slope crudes.

- Alternate 7: No knowledge.

- Alternate 8: No significant time delay is involved if this course is required.

- Alternate 9: If a government policy decision were made authorizing exchanges with refiners in non-contiguous foreign countries, U.S. suppliers may be able to complete negotiations in 3-6 months.

D. Federal Policy Role

1. If none of the pipeline systems listed in IV-A, 1-3 (Kitimat, Northern Tier, and Sohio) is approved and constructed in time to transport any of the anticipated West Coast surplus in PAD V created by North Slope crude oil production, how would you recommend the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV-A, 4-9.)

   - In the absence of any transcontinental pipeline, the producers of the surplus crude are likely on a short-term basis to move it to the U.S. Gulf/East Coast through the Panama Canal. If government studies indicate that exchanges with refiners in noncontiguous foreign countries are appropriate, that, too, may represent a feasible solution. Retrofitting of the refineries could reduce the surplus in the 1980-85 period.

2. What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?

   - We are not aware of any policy objections; however, exports in exchange for imports would appear to be more in the national interest.

3. a. Is there need for federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PAD V?

      - Federal, state and local governments should expedite the necessary hearing and permitting processes that will allow the various pipeline proposals to be promptly considered on their merits so that all of the viable projects can proceed without undue delay. There is no evidence that this requires any added federal legislation at this time.

   b. What, if any, constraints should such legislation address?

      - Not applicable.

V. Costs and Prices

A. What is the full anticipated cost of constructing and equipping the Trans-Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?

   - Alyeska Pipeline Service Company has estimated the Trans-Alaska Pipeline System including terminal facilities will cost $7.7 billion for 1.2 million barrels per day capacity. Discussions are under way with Alyeska to determine the facilities required at the stations and terminals for increases in system capacity. Interest costs during construction are incurred by the individual owners and are not included in the above total.

B. What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985? (Specify throughput assumptions.) What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?

- Pipeline tariffs from Prudhoe Bay to Valdez must be filed with the appropriate governmental authorities. Pending the filing of such tariffs, we are conducting our present planning on the assumption that such tariffs will be about $5 per barrel in the early years of operation and about $4 per barrel in the 1985 time frame.

- With the projected uncertainty of Jones Act ship requirements immediately following TAPS start-up, it is difficult to project marine rates during that period.

- In later years, if newbuilding for delivery in 1980 of a 190 MDWT vessel were assumed at today's costs and the owner received a reasonable return on the investment, we would expect rates from 1980 to 1985 on that vessel for shipments from Valdez to the average West Coast port to be about $1.00 to $1.15/B.

C. To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act, or (b) at the upper tier price established by FEA, be expected to constrain West Coast refinery prices? Refinery prices East of the Rockies?

D. If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g. imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?

E. To what extent, if at all, would the alternative measures identified in question IV-A affect average prices of North Slope and similar grade crude oil produced in PAD V (a) at the wellhead, (b) at West Coast refineries, and (c) at refineries East of the Rockies?

V., C., D., & E.

North Slope Pricing

There are several unresolved factors that affect wellhead prices or realizations, costs of crude to West Coast refiners and crude prices in other parts of the country. Some of the main uncertainties are:

1. The FEA ceiling price.
2. The treatment of North Slope crude under the Entitlement Program.
3. Prices and quality of crude from alternate sources.
4. Market conditions.
5. Possible transportation cost alternatives.

An assessment of each of these factors involves various degrees of uncertainties which tend to be magnified when combined in a pricing estimate. Any estimates of these factors and their interaction are necessarily speculative. For these reasons speculation on future prices under conditions of such uncertainty would not be fruitful and would be inconsistent with federal antitrust principles.

ATTACHMENT A

TABLE 14. - Imports of foreign crude oil[1]

(Thousands of barrels)

P.A.D. District and Country of Origin	February 1976	January 1976	February 1975	January - February (Incl.) 1976	January - February (Incl.) 1975
All Districts:					
Algeria	10,149	10,295	5,910	20,444	14,394
Angola	-	1,035	1,666	1,035	4,346
Bolivia	276	-	-	276	-
Canada[2]	10,009	13,128	17,770	23,137	39,148
Congo (Brazzaville)	-	292	-	292	-
Ecuador	361	1,557	1,644	1,918	3,274
Egypt	995	957	-	1,952	-
England	-	331	-	331	-
Gabon	1,337	550	1,079	1,887	1,211
Indonesia	13,494	14,812	8,920	28,306	17,364
Iran	6,996	11,972	8,092	18,968	20,286
Kuwait	-	-	99	-	99
Libya	9,460	13,429	2,301	22,889	2,881
Malaysia	-	-	224	-	336
Mexico	2,029	1,820	1,285	3,849	1,783
Nigeria	23,796	23,977	23,313	47,773	49,436
Norway	215	412	-	627	-
Oman	440	94	-	534	-
Qatar	324	397	-	721	1,746
Saudi Arabia	31,241	34,407	22,101	65,648	48,305
Trinidad	3,915	4,770	2,334	8,685	4,813
Tunisia	348	394	-	742	422
United Arab Emirates	3,436	3,684	2,964	7,120	4,417
Venezuela	3,209	4,114	7,492	7,323	17,834
Total[2]	122,030	142,427	107,194	264,457	232,095
To District I:					
Algeria	6,860	5,423	1,825	12,283	5,925
Angola	-	708	1,466	708	4,054
Canada	432	522	2,442	954	4,725
Ecuador	239	-	-	239	-
Egypt	995	957	-	1,952	-
Gabon	492	550	770	1,042	902
Indonesia	985	1,253	317	2,238	660
Iran	3,655	6,575	2,548	10,230	7,450
Kuwait	-	-	99	-	99
Libya	1,159	2,672	703	3,831	703
Mexico	-	-	757	-	1,056
Nigeria	6,318	7,107	8,179	13,425	17,939
Saudi Arabia	10,178	11,303	7,071	21,481	15,572
Trinidad	-	-	823	-	1,226
United Arab Emirates	659	1,090	1,819	1,749	2,258
Venezuela	3,046	3,264	5,439	6,310	12,322
Total	35,018	41,424	34,258	76,442	74,891

Continued on next page.

ATTACHMENT A - Pg 2

TABLE 14. - Imports of foreign crude oil[1] (continued)

(Thousands of barrels)

P.A.D. District and Country of Origin	February 1976	January 1976	February 1975	January - February (Incl.) 1976	January - February (Incl.) 1975
To District II:					
Algeria	1,376	752	1,463	2,128	3,191
Canada[2]	4,833	7,782	9,218	12,615	21,173
Ecuador	108	-	-	108	-
Iran	732	1,693	785	2,425	2,231
Libya	4,983	7,236	-	12,219	-
Nigeria	4,326	4,699	5,014	9,025	9,032
Qatar	324	-	-	324	142
Saudi Arabia	3,519	2,658	1,843	6,177	3,549
Trinidad	978	1,536	31	2,514	705
United Arab Emirates	743	3	-	746	-
Venezuela	-	351	488	351	2,219
Total[2]	21,922	26,710	18,842	48,632	42,242
To District III:					
Algeria	1,913	4,059	2,622	5,972	5,278
Angola	-	327	200	327	292
Canada	-	-	-	-	121
Congo (Brazzaville)	-	292	-	292	-
Ecuador	-	308	-	308	-
England	-	331	-	331	-
Gabon	-	-	309	-	309
Indonesia	2,070	1,693	1,235	3,763	2,210
Iran	-	381	935	381	2,777
Libya	3,318	3,480	1,598	6,798	2,178
Mexico	2,029	1,820	528	3,849	727
Nigeria	13,129	12,151	10,120	25,280	22,465
Norway	215	412	-	627	-
Qatar	-	-	-	-	1,096
Saudi Arabia	14,101	16,103	10,982	30,204	22,594
Trinidad	2,937	3,234	1,480	6,171	2,882
Tunisia	348	394	-	742	422
United Arab Emirates	698	1,123	-	1,821	7
Venezuela	78	230	1,140	308	2,589
Total	40,836	46,338	31,149	87,174	65,947
To District IV:					
Canada	1,438	1,458	1,495	2,896	2,979
To District V[3]:					
Algeria	-	61	-	61	-
Bolivia	276	-	-	276	-
Canada	3,306	3,366	4,615	6,672	10,150
Ecuador	14	1,249	1,644	1,263	3,274
Gabon	845	-	-	845	-
Indonesia	10,439	11,866	7,368	22,305	14,494
Iran	2,609	3,323	3,824	5,932	7,828
Libya	-	41	-	41	-
Malaysia	-	-	224	-	336
Nigeria	23	20	-	43	-
Oman	440	94	-	534	-
Qatar	-	397	-	397	508
Saudi Arabia	3,443	4,343	2,205	7,786	6,590
United Arab Emirates	1,336	1,468	1,145	2,804	2,152
Venezuela	85	269	425	354	704
Total	22,816	26,497	21,450	49,313	46,036

[1] Reported to the Bureau of Mines.
[2] Includes some Athabasca hydrocarbons.
[3] Excludes crude oil delivered into foreign trade zone.

ATTACHMENT A - Pg 3

TABLE 15. - Imports of finished petroleum products including receipts from Puerto Rico, the Virgin Islands, and Guam by P.A.D. District

(Thousands of barrels)

	February 1976	January 1976	February 1975	January - February (Incl.) 1976	1975
All Districts:					
Motor gasoline, total	2,427	2,850	4,784	5,277	12,899
Receipts from Puerto Rico	413	527	1,557	940	3,420
Other	[1]2,014	2,323	3,227	4,337	9,479
Naphtha-type jet fuel, total	642	323	984	965	1,716
Bonded aircraft fuel	-	-	-	-	112
Other	[1]642	323	984	965	1,602
Kerosine-type jet fuel, total	1,442	1,811	4,604	3,253	10,985
Bonded aircraft fuel	461	642	1,433	1,103	3,756
Receipts from Puerto Rico	-	-	-	-	-
Other	981	1,169	3,171	2,150	7,229
Liquefied petroleum gases	4,140	4,824	3,237	8,964	8,775
Kerosine, total	368	8	234	376	533
Receipts from Puerto Rico	-	8	16	8	39
Other	368	-	218	368	494
Distillate fuel oil, total	5,669	5,024	8,453	10,693	18,494
Bonded ships bunkers	94	188	342	282	707
Receipts from Puerto Rico	1,149	466	1,472	1,615	2,316
No. 2 fuel oil	[1]2,667	3,087	4,684	5,754	11,703
No. 4 fuel oil	[1]1,759	1,283	1,953	3,042	3,768
Residual fuel oil, total	47,160	41,950	39,269	89,110	90,312
Bonded ships bunkers	848	1,525	1,579	2,373	5,032
Receipts from Puerto Rico	1,182	672	275	1,854	309
For military offshore use	-	-	-	-	-
Other	[1]45,130	39,753	37,415	84,883	84,971
Petrochemical feedstocks, total	233	581	-	814	974
Receipts from Puerto Rico	-	-	-	-	-
Other	233	581	-	814	974
Special naphthas	1	2	30	3	30
Lubricants	45	162	184	207	274
Wax	32	61	78	93	133
Asphalt	167	407	303	574	556
Miscellaneous	55	290	418	345	682
Total	62,381	58,293	62,578	120,674	146,361
District I:					
Motor gasoline, total	2,427	2,850	4,548	5,277	12,232
Receipts from Puerto Rico	413	527	1,557	940	3,420
Other	2,014	2,323	2,991	4,337	8,812
Naphtha-type jet fuel, total	287	290	823	577	1,441
Bonded aircraft fuel	-	-	-	-	-
Other	287	290	823	577	1,441
Kerosine-type jet fuel, total	737	782	2,202	1,519	6,302
Bonded aircraft fuel	196	408	820	604	2,379
Receipts from Puerto Rico	-	-	-	-	-
Other	541	374	1,382	915	3,923
Liquefied petroleum gases	966	795	878	1,761	2,833
Kerosine, total	368	8	234	376	533
Receipts from Puerto Rico	-	8	-	8	-
Other	368	-	234	368	533
Distillate fuel oil, total	5,515	4,754	8,143	10,269	17,914
Bonded ships bunkers	19	188	180	207	407
Receipts from Puerto Rico	1,149	466	1,472	1,615	2,316
No. 2 fuel oil	2,588	2,830	4,643	5,418	11,565
No. 4 fuel oil	1,759	1,270	1,868	3,029	3,626
Residual fuel oil, total	44,998	40,580	37,031	85,578	84,138
Bonded ships bunkers	760	1,525	1,550	2,285	4,775
Receipts from Puerto Rico	1,182	672	275	1,854	309
For military offshore use	-	-	-	-	-
Other	43,056	38,383	35,206	81,439	79,074
Petrochemical feedstocks	-	-	-	-	378
Special naphthas	-	-	-	-	-
Lubricants	45	162	182	207	272
Wax	32	60	76	92	129
Asphalt	167	407	303	574	556
Miscellaneous	55	290	418	345	682
Total	55,597	50,976	54,836	106,575	127,430
District II:					
Motor gasoline	-	-	-	-	-
Kerosine-type jet fuel, total	30	35	116	65	231
Bonded aircraft fuel	30	1	116	31	231
Other	-	34	-	34	-
Liquefied petroleum gases	1,901	2,267	1,047	4,168	3,082
Kerosine	-	-	-	-	-
Distillate fuel oil, total	-	-	29	-	70
No. 2 fuel oil	-	-	29	-	69
No. 4 fuel oil	-	-	-	-	1
Residual fuel oil	[1]1,071	805	1,097	1,876	2,344
Special naphthas	1	2	30	3	30
Lubricants	-	-	1	-	1
Wax	-	-	-	-	-
Asphalt	-	--	-	-	-
Total	3,003	3,109	2,320	6,112	5,978

See footnotes at end of table.

ATTACHMENT A - Pg 4

TABLE 15. - Imports of finished petroleum products including receipts from Puerto Rico, the Virgin Islands, and Guam by P.A.D. District (continued)

(Thousands of barrels)

	February 1976	January 1976	February 1975	January - February (Incl.) 1976	1975
District III:					
Motor gasoline	-	-	33	-	691
Naphtha-type jet fuel, total	-	-	-	-	112
Bonded aircraft fuel	-	-	-	-	112
Other	-	-	-	-	-
Kerosine-type jet fuel, total	-	-	267	-	615
Bonded aircraft fuel	-	-	16	-	71
Other	-	-	251	-	544
Liquefied petroleum gases	254	188	288	442	389
Kerosine	-	-	-	-	-
Distillate fuel oil, total	75	-	71	75	211
Bonded ships bunkers	75	-	71	75	179
No. 2 fuel oil	-	-	-	-	32
Residual fuel oil, total	329	-	376	329	989
Bonded ships bunkers	88	-	29	88	257
For military offshore use	-	-	-	-	-
Other	241	-	347	241	732
Petrochemical feedstocks, total	233	581	-	814	596
Receipts from Puerto Rico	-	-	-	-	-
Other	233	581	-	814	596
Special naphthas	-	-	-	-	-
Lubricants	-	-	-	-	-
Wax	-	1	2	1	4
Asphalt	-	-	-	-	-
Total	891	770	1,057	1,661	3,317
District IV:					
Motor gasoline	-	-	-	-	6
Liquefied petroleum gases	579	903	505	1,482	1,371
Distillate fuel oil	-	-	-	-	1
Residual fuel oil	-	-	-	-	-
Special naphthas	-	-	-	-	-
Lubricants	-	-	-	-	-
Total	579	903	505	1,482	1,378
District V:					
Motor gasoline	-	-	183	-	280
Naphtha-type jet fuel, total	355	33	161	388	161
Bonded aircraft fuel	-	-	-	-	-
Other	355	33	161	388	161
Kerosine-type jet fuel, total	675	994	2,019	1,669	3,837
Bonded aircraft fuel	235	233	481	468	1,075
Other	440	761	1,538	1,201	2,762
Liquefied petroleum gases	440	671	519	1,111	1,100
Kerosine	-	-	-	-	-
Distillate fuel oil, total	79	270	210	349	398
Bonded ships bunkers	-	-	111	-	121
No. 2 fuel oil	79	257	14	336	36
No. 6 fuel oil	-	13	85	15	141
Residual fuel oil, total	762	565	765	1,327	2,601
Bonded ships bunkers	-	-	-	-	-
For military offshore use	-	-	-	-	-
Other	762	565	765	1,327	2,601
Special naphthas	-	-	-	-	-
Lubricants	-	-	1	-	1
Wax	-	-	-	-	-
Asphalt	-	-	-	-	-
Total	2,311	2,533	1,818	4,844	8,238

Note: Imports for onshore use of military jet fuel, distillate and residual fuel oils, and receipts from Puerto Rico, the Virgin Islands, and Guam are based on data reported to the Department of the Interior and the Federal Energy Administration. All other import figures are compiled from Department of Commerce data.

[1] Includes receipts from the Virgin Islands: (In thous. bbls.) District I: Gasoline, 1,636; Naphtha-type jet, 287; Distillate #2 oil, 1,677; Distillate #4 oil, 347; Residual fuel oil, 8,915. District III: Residual fuel oil, 35.

[2] Includes crude oil for direct burning as fuel: (In thous. bbls.) District II: 347,000 barrels.

TABLE 16. - Imports of plant condensate[1] and unfinished oils

(Thousands of barrels)

	February 1976	January 1976	February 1975	January - February (Incl.) 1976	1975
Plant condensate[1], total	1,586	2,616	1,836	6,202	4,260
P.A.D. District I	280	333	231	613	564
P.A.D. District II	2,515	1,381	899	3,896	2,101
P.A.D. District III	-	65	-	65	-
P.A.D. District IV	702	840	605	1,542	1,309
P.A.D. District V	189	197	101	386	272
Unfinished oils, total	1,634	1,586	1,323	3,240	2,244
P.A.D. District I	[2]1,314	1,265	738	2,579	870
P.A.D. District II	-	-	-	-	-
P.A.D. District III	340	266	513	606	1,026
P.A.D. District V	-	55	72	55	350

[1] Includes natural gasoline.

[2] Includes receipts from Puerto Rico: 710,000 barrels.

GATX

GENERAL AMERICAN
TRANSPORTATION CORPORATION

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October 8, 1976

File: GS 462.18.3-26

Ms. Betsy Moler
Professional Staff Member
UNITED STATES SENATE
Committee on Interior and Insular Affairs
Washington, D.C. 20510

Dear Ms. Moler:

Thank you for your letter of September 10, in which you asked for more information about the TANK TRAIN proposals we have made for the shipment of crude oil. Also with the letter was a questionnaire.

You will receive under separate cover, the following descriptive data:

- 1976 GATX Annual Report which describes our businesses and our financial condition;
- TANK TRAIN brochures, which describe the TANK TRAIN system;
- "GATX TANK TRAIN Proposal for Moving Crude Oil from Long Beach, California to Midwestern Points" booklet, which describes the transportation proposal GATX made to ARCO, SOHIO, and other oil companies in association with the Santa Fe, Southern Pacific, and Missouri Pacific railroads;
- "TANK TRAIN for the Northern Tier Refineries" booklet, which is a reply to the U.S. Department of Transportation relative to a study they were making for the Federal Energy Administration;
- Brochure describing the Portal Pipe Line Co. - Burlington Northern R.R. proposal to transport crude oil to the Northern Tier Refineries.

GENERAL AMERICAN TRANSPORTATION CORPORATION (GATX) is a wholly owned subsidiary of GATX CORPORATION. We are the world's largest manufacturer and lessor of railroad tank cars, which are manufactured at our Sharon, Pa. - Masury, Ohio plant. Our tank car fleet consists of 53,000 cars of various classifications and sizes, leased to hundreds of American industries. Railroads do not provide tank cars to their customers nor lease tank cars for their customers because tank cars are custom built vehicles.

TANK TRAIN is a long-term solution for the transportation of crude oil from the West Coast to midwestern points, and is the most flexible transportation alternative for the Strategic Crude Oil Reserve Program. TANK TRAIN offers:

- Cost competitive with pipelines at volumes up to 300,000 b/d;
- The utilization of well managed and financially sound common carrier railroad systems, such as the Santa Fe, Southern Pacific, Missouri Pacific and Burlington Northern (but not to exclude the Denver Rio Grande Western, Union Pacific, Western Pacific, and The Milwaukee Road, with whom we are presently not engaged in active TANK TRAIN proposals);
- A safe, environmentally acceptable tank car transportation system that has a completely closed loading and unloading operation.

TANK TRAIN can be introduced within 6 months after an order is culminated, at volumes up to 200 cars per month. It is probable that within 19 months after receipt of an order for 2,400 TANK TRAIN cars, a fleet would exist with the capacity of roughly 230,000 b/d (Long Beach to Midland).

GATX recognizes that various oil companies believe it will take 2 to 3 years before very high volumes of crude oil can begin to move in the 500,000 b/d pipelines being planned. TANK TRAIN can be used in start-up operations for SOHIO, as an example, until such time as their pipeline becomes operational.

We cannot build and lease the large number of TANK TRAIN or other types of tank cars that will be required for this service, for lease periods of one to five years, without achieving a full payout and profit on these cars. The tank car market could not absorb this large number of general service TANK TRAIN cars at one time, and, we would compete with our production of new cars which could result in layoffs.

GATX proposes to the Committee on Interior and Insular Affairs, the oil industry, and the FEA, a plan by which GATX will lease the necessary TANK TRAIN cars to the oil industry at special lease rates and for the interim period needed - with the residual being purchased by the FEA for use in the Strategic Crude Oil Reserve Program. The MITRE Corp. is making a distribution study for the FEA on the Strategic Crude Oil Reserve Program. MITRE's Mr. R. B. Ryan is aware of the potential of TANK TRAIN for this Program. Additionally, the Department of Defense's Military Traffic Management Command could use these cars on a rotation basis, as replacement cars for their aging general service tank car fleet.

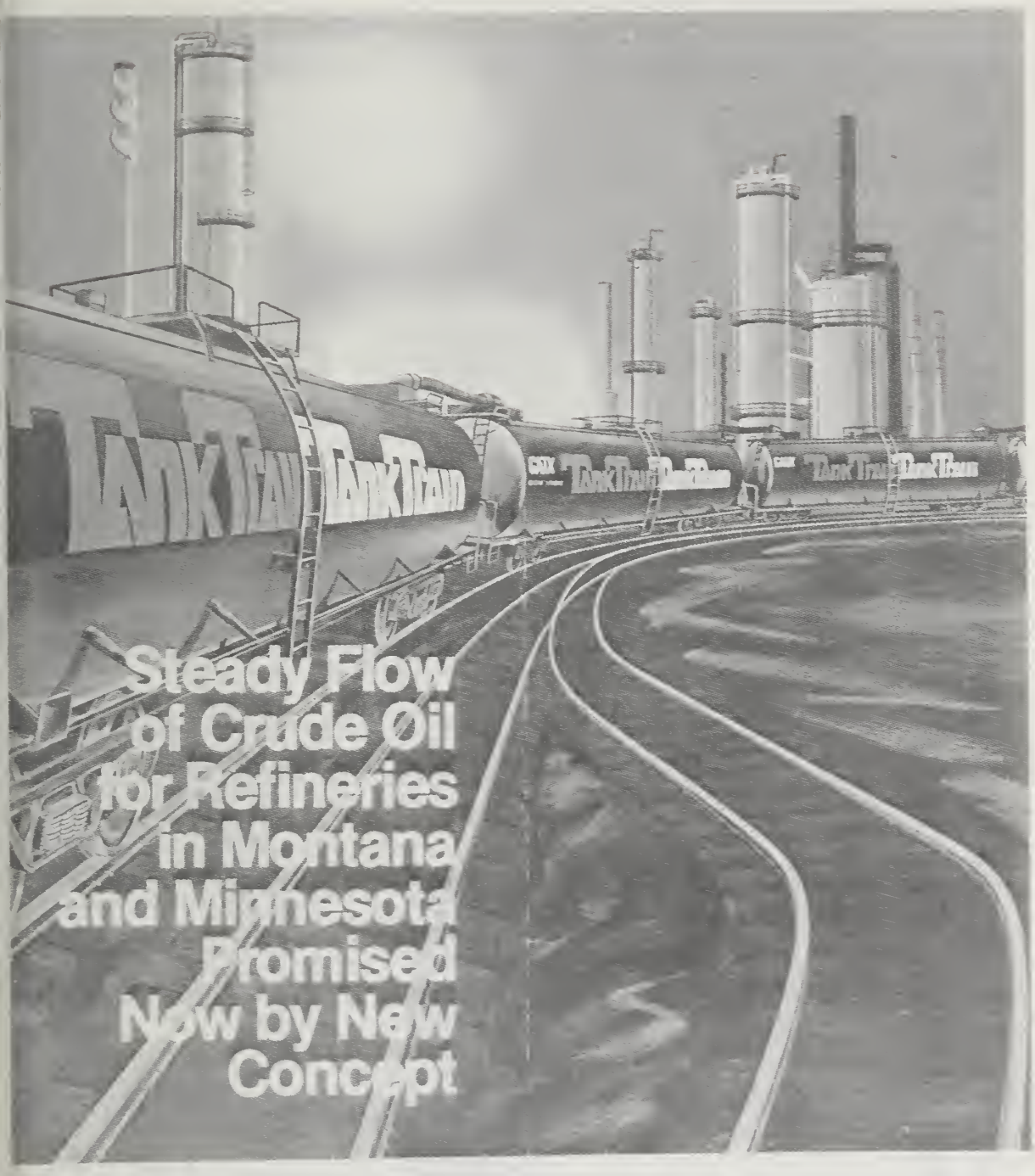
In conclusion, Ms. Moler, the use of TANK TRAIN for the transportation of some of the Alaskan crude oil will definitely have a positive impact on the common carrier railroad systems in the United States, and more importantly, on the American consumer. TANK TRAIN can move the Alaskan crude oil efficiently and effectively beginning in late 1977, early 1978.

Very truly yours,

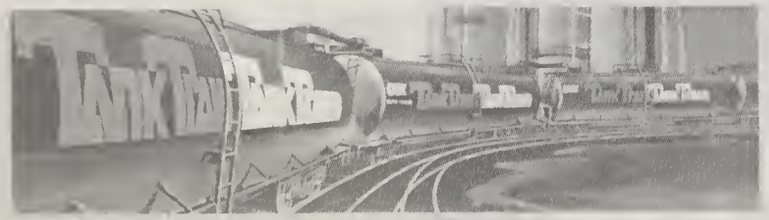
Marcus S. Kostolich
Assistant to the
Director of Planning

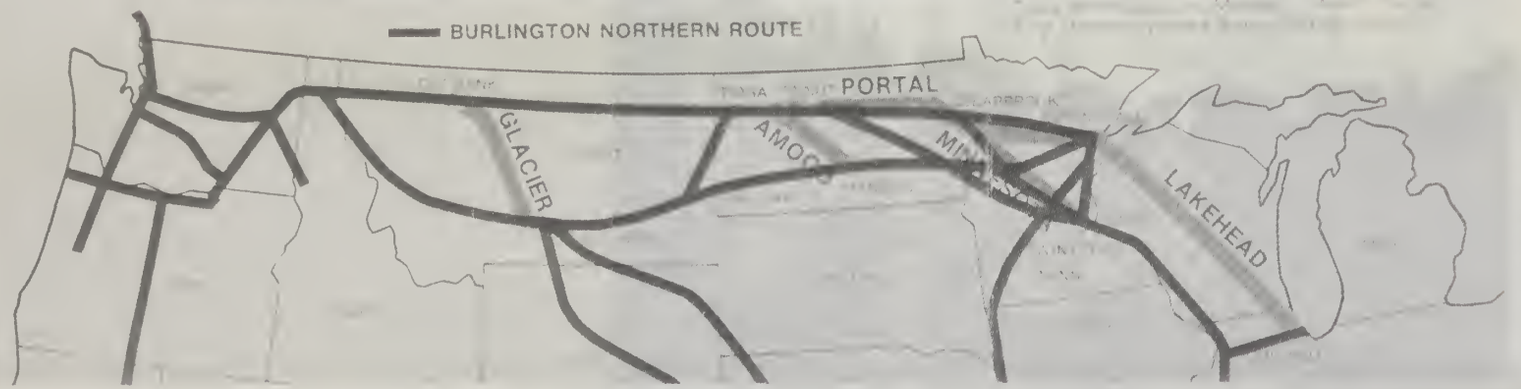
MSK:sam

(Editor's Comment: The two TANK TRAIN brochures and a summary of the "GATX TANK TRAIN proposal for Moving Crude Oil from Long Beach, California to Midwestern Points" have been reproduced following this letter. The other materials have been retained in the Committee's files.)


Steady Flow
of Crude Oil
for Refineries
in Montana
and Minnesota
Promised
Now by New
Concept

"Pipeline on Wheels" Links Pacific Northwest Port to U.S. Pipelines Supplying Priority 1 Refineries





Supply of Crude Oil Could Be Short

The Canadian government has announced a plan for curtailing their exports of crude petroleum to the United States. The plan calls for less oil each year until it is shut off completely in 1982.

This means real deficits of crude oil delivered to Priority 1 refineries in Montana and Minnesota could occur. According to the Canadian schedule, these U.S. refineries will experience the following minimum deficits (in thousands of barrels per day):

	1977	1978	1979	1980	1981	1982
Montana	9	26.6	46.3	53.5	60	66.9
Minnesota group	55.7	104.4	160.1	180.7	215.1	218.5

Pipeline Across Canada Proposed

A Western Canada pipeline has been proposed from the Pacific Northwest port of Kitimat, British Columbia, to Edmonton, Alberta. The goal of this pipeline is to transport most of the crude oil from Alaska's Prudhoe Bay and other sources. The Interpro system would transport the oil from Edmonton to the Priority 1 refining areas.

This proposed pipeline would not be ready for operation before 3 to 5 years. Alaskan oil will not be flowing from the Prudhoe Bay fields for 1½ years. The Canadians are clamping their supply line tighter and tighter so deficits of crude will occur as early as 1977.

Cost of the Western Canada pipeline was originally pegged at $400 million. But based on experience, this figure may be way short as latest estimates are up 25%. As an example, the Alyeska Pipeline was budgeted at $700 million but latest forecasts call for $8 billion.

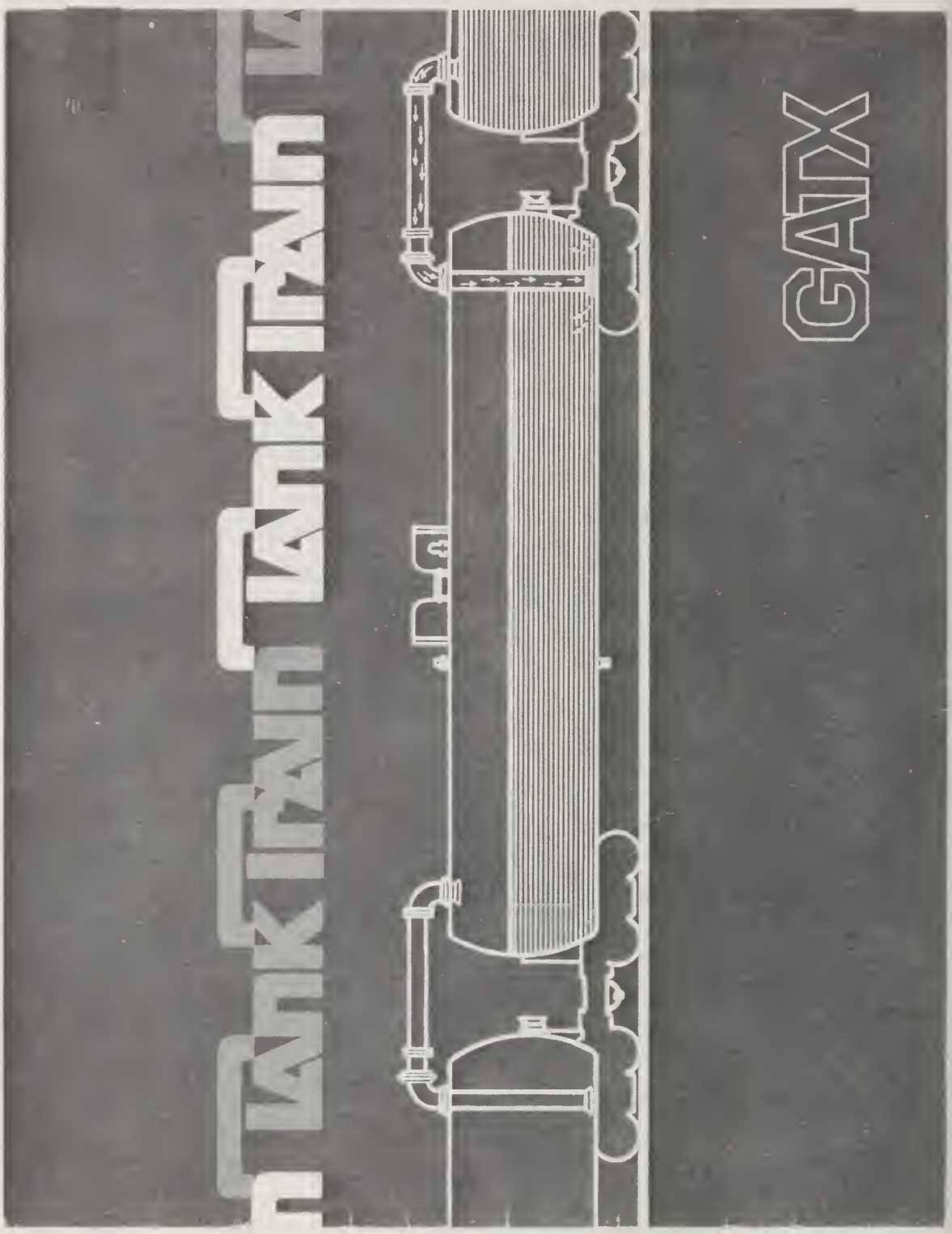
Price is Right, Service is Set. Call Us and Let's Get Going.

Call us and let's get going with this All-American plan. This project is a total team effort to serve your crude oil needs and is backed by GATX, Burlington Northern and Portal Pipe Line Company. Call any one of the persons listed below -- and let's get going.

Portal Pipe Line Company
Mark Nicholas (701) 852-1087

GATX
M.S. Kostolich (312) 621-6322

Burlington Northern
Michael Karl (612) 298-3234


GATX

TANK TRAIN

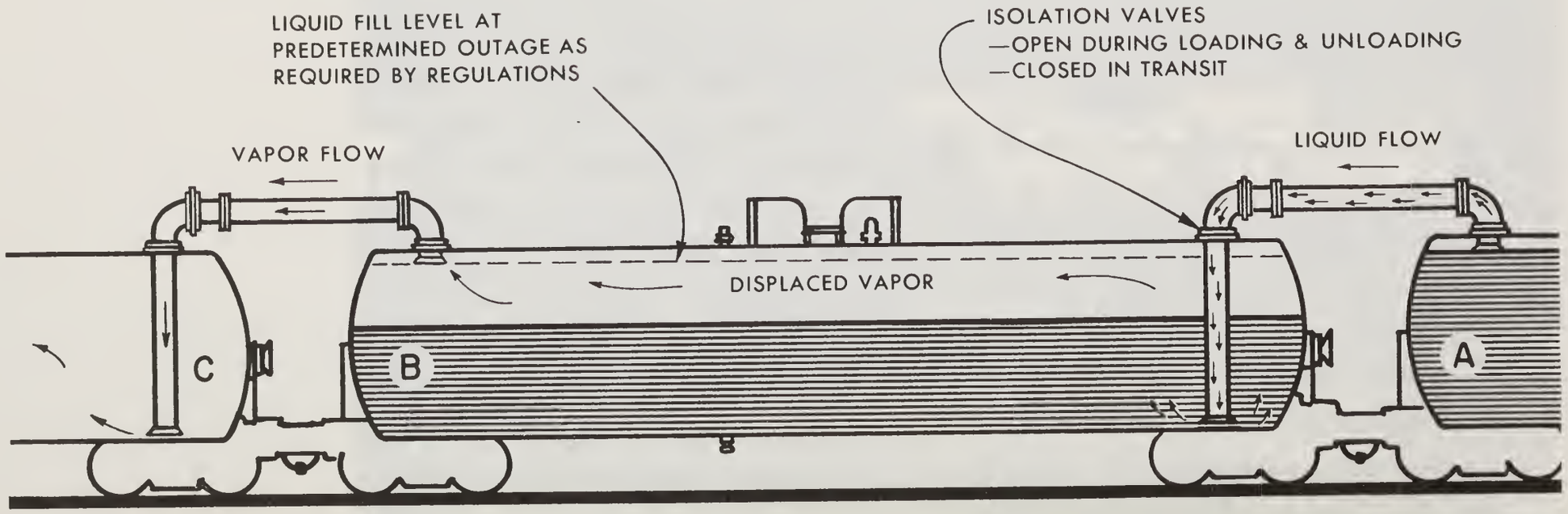
BULK LIQUID INTERCONNECTED TANK CAR SYSTEM

GATX has developed a new concept for the efficient loading, transporting and unloading of bulk liquids using INTERCONNECTED TANK CAR UNIT TRAINS.

This new GATX system involves a string of interconnected tank cars, such that via a SINGLE CONNECTION, a large number of tank cars can be loaded or unloaded.

The essential features of the system are shown in Figure 1. Connections, complete with a flexible hose section and tank isolation valves, are installed between each pair of tank cars. A string of tank cars can be loaded with liquid commodity through a pump connected to the first car. Displaced vapors may be vented to the atmosphere or processed through a flare or scrubbing equipment or even collected and recycled to process storage.

At the unloading site, a reverse procedure can be used to unload the entire car string, using compressed air or inert gas, depending upon the flammable characteristics of the liquid involved. An unloading pump can be incorporated to increase the unloading flow rate. It is also feasible to incorporate a pressurized gas tank car, filled with nitrogen, for example, into the car string, such that the entire car string will self-unload, via a SINGLE PIPE CONNECTION, *without any equipment or facility whatsoever at the unloading site.*



BASIC FLOW DIAGRAM DURING LOADING PHASE
INTERCONNECTED TANK CARS

Figure 1

The TANK TRAIN concept is particularly applicable to the transportation by tank car unit train of crude oil and other liquid products for which no other efficient and safe system of loading and unloading is currently available.

The ADVANTAGES of the GATX system over individual loading and unloading of tank cars (including unloading via gravity into belowgrade pits) are:

- **LESS HANDLING.** Loading and unloading are facilitated by only two connections at the intake and discharge of a tank car string.

- **GREATER FLOW RATES.** Due to the use of pumps and of a compressed gas pad rather than gravity flow, loading *and* unloading rates to the order of 3000 GPM can be achieved for as many as 40 cars, all interconnected.

- **INCREASED SAFETY.** The "closed" system approach utilizes inert gases rather than air in providing padding pressure to the discharge pump inlet. Since petroleum products are often heated to decrease viscosity in order to increase flow rates, the lower explosive limit becomes an important safety consideration.

- **ENVIRONMENTAL ACCEPTABILITY.** The odor and fumes, given off when some petroleum products are loaded through an open manway or gravity dumped into open pits, can be easily and controllably collected via a single connection to a tank car string.

- **MINIMUM CAPITAL INVESTMENT.** Using the GATX system eliminates the expensive multiple-position loading rack structure, loading arms, valves, piping, etc. Equally, at the unloading site, the system eliminates the belowgrade pits and the complex system of pumps and piping for transmission of peak flow gravity dump sequences when six or seven tank cars are gravity-unloaded simultaneously.

- **MINIMUM OPERATING LABOR.** Both from the carrier (railroad) viewpoint and the shipper and receiver viewpoints, the system requires the absolute minimum of effort in positioning the tank cars both at the loading and unloading sites. Thus, quick turn-around times can be achieved leading to maximum utilization of equipment and operational staff.

- **GREATER MARKET PENETRATION.** With the GATX system, there is no requirement for elaborate and expensive rail trackage. Thus, a unit train can be loaded and unloaded at terminals with minimum in-plant spur tracks. With the use of the integral pressurized gas tank car, the unit train can be unloaded at "spot" locations without any in-plant equipment or services — the only requirement being a single pipe connection leading to in-plant storage capacity. Thus from the shippers' and carriers' viewpoints, a unit train load of fuel oil, for example, could be marketed to industry or public utility on a "spot" shipment basis, a trial evaluation basis, or even on an emergency energy gap basis.

It should be noted in addition that the cars can also be routinely top-loaded and bottom-unloaded on an individual per-car basis — all leading to the maximum flexibility of operation and utilization of all or each single car.

TECHNICAL DESCRIPTIONS

The basic flow pattern is as shown in Figure 1. Here a liquid, having filled tank car A, is now filling tank car B and exhausting displaced vapors through tank car C. Note the CONTROLLED OUTAGE condition in tank car A and the IN-TRANSIT ISOLATION VALVES.

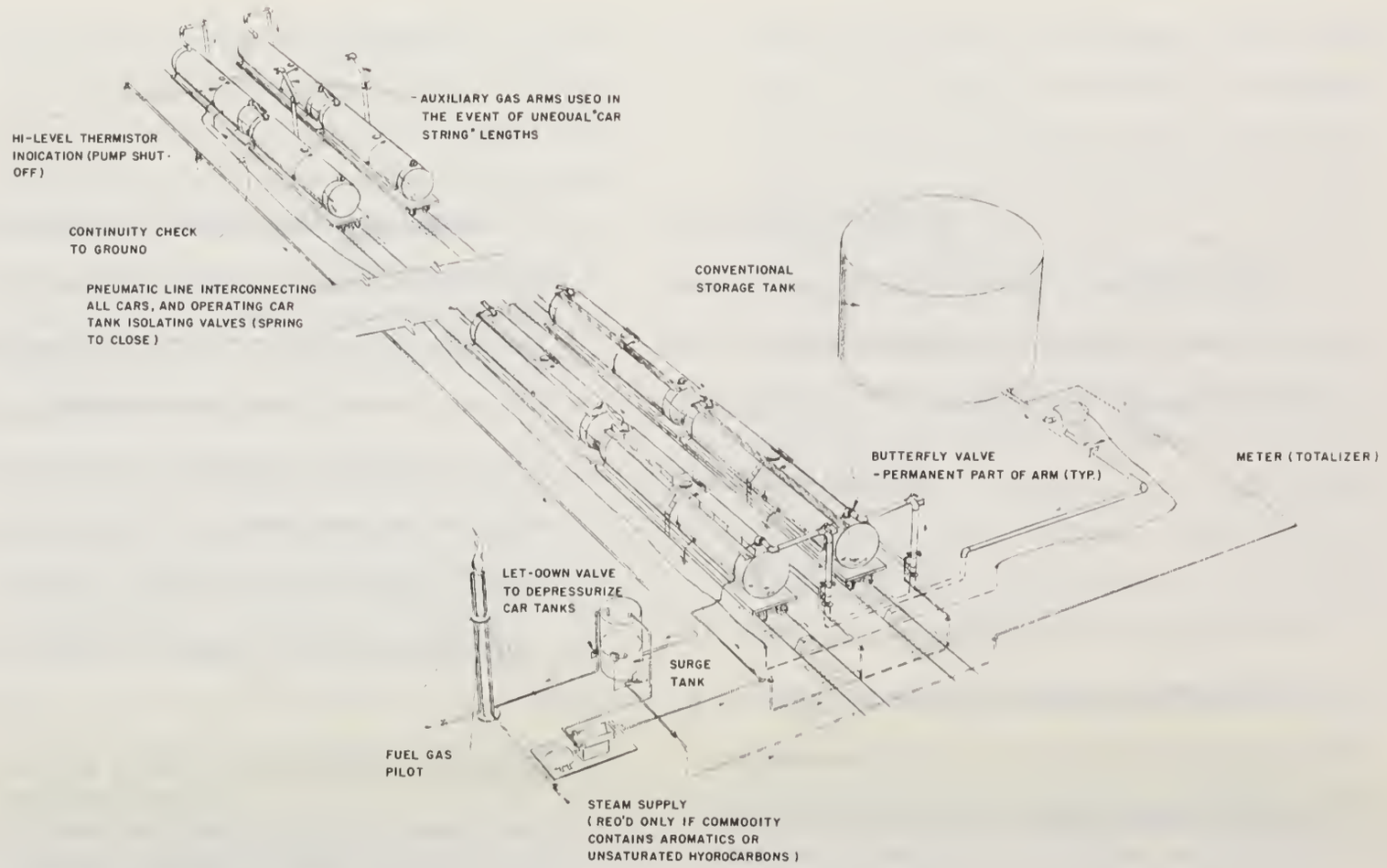
The concept of pumping a liquid through interconnected tank cars has been successfully tested by GATX at its Sharon, Pennsylvania tank car facility. Flow rates of over 3000 GPM through the 10-inch diameter interconnection was achieved. The test liquid was water, which approximately simulates the flow of hot crude oil at 150°F. However, the system has been designed to handle most bulk liquids.

Two basic systems are envisioned which are capable of handling the entire range of viscosities and volatilities of petroleum products:

1. A closed system to handle crude oil and products of relatively high volatility (see Figures 2, 3 and 4).
2. A simplified system to handle petroleum products with low volatility such as #6 oil (see Figures 5 and 6).

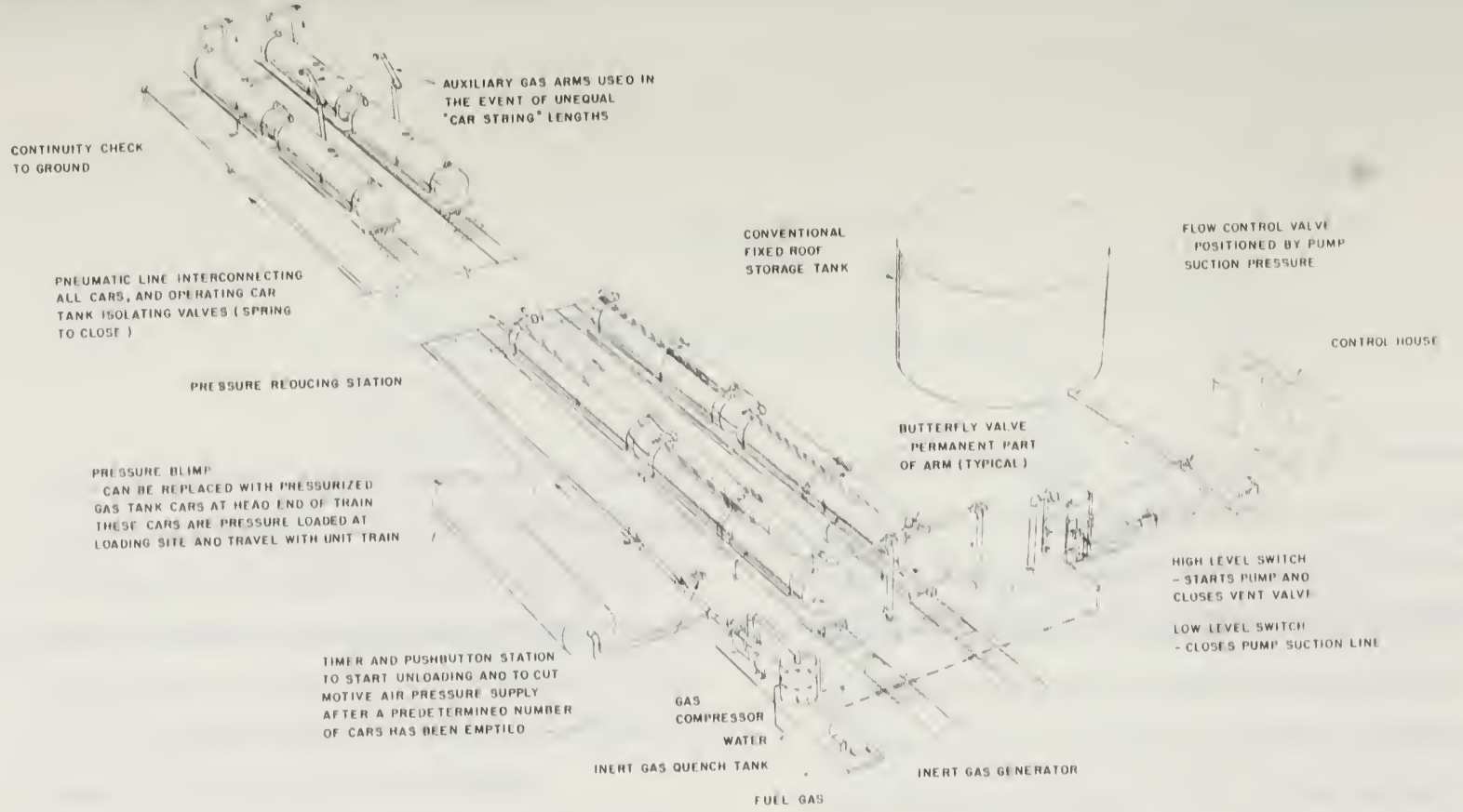
CLOSED SYSTEM

The facilities for loading and unloading in a closed system are shown in Figures 2 and 3. A closed system is recommended for handling volatile organic compounds.


HI-LEVEL THERMISTOR INOICATION (PUMP SHUT-OFF)
AUXILIARY GAS ARMS USED IN THE EVENT OF UNEQUAL "CAR STRING" LENGTHS
CONTINUITY CHECK TO GROUND
PNEUMATIC LINE INTERCONNECTING ALL CARS, AND OPERATING CAR TANK ISOLATING VALVES (SPRING TO CLOSE)
CONVENTIONAL STORAGE TANK
BUTTERFLY VALVE - PERMANENT PART OF ARM (TYP.)
METER (TOTALIZER)
LET-DOWN VALVE TO DEPRESSURIZE CAR TANKS
SURGE TANK
FUEL GAS PILOT
STEAM SUPPLY (REQ'D ONLY IF COMMODITY CONTAINS AROMATICS OR UNSATURATED HYDROCARBONS)

LOADING
"CLOSED SYSTEM"

Figure 2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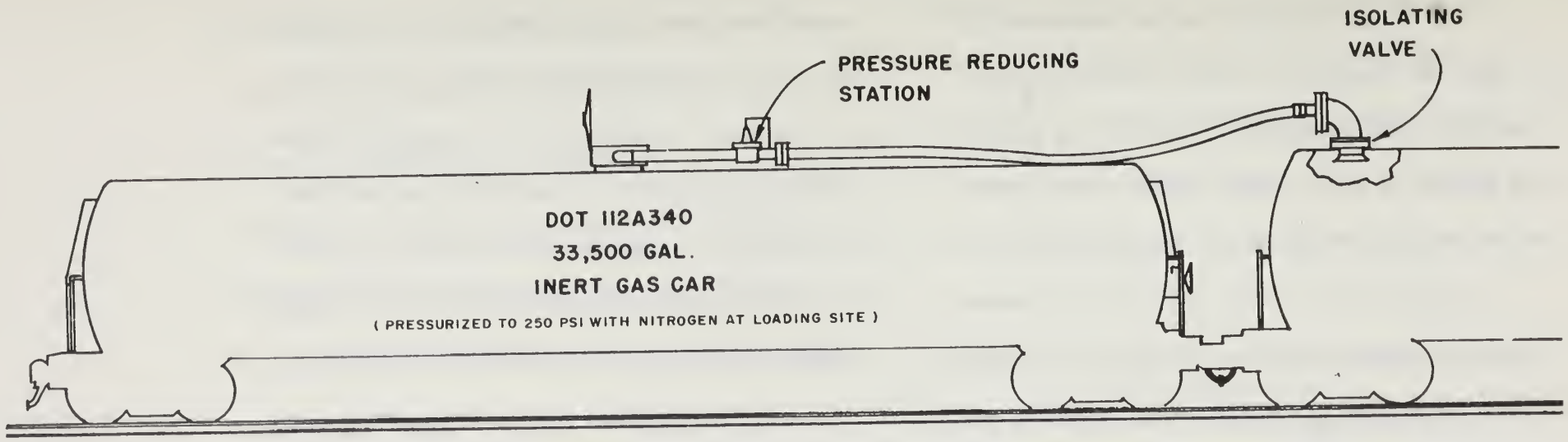
CONTROL HOUSE
PRESSURE REDUCING STATION
BUTTERFLY VALVE PERMANENT PART OF ARM (TYPICAL)
PRESSURE BLIMP CAN BE REPLACED WITH PRESSURIZED GAS TANK CARS AT HEAD END OF TRAIN THESE CARS ARE PRESSURE LOADED AT LOADING SITE AND TRAVEL WITH UNIT TRAIN
HIGH LEVEL SWITCH - STARTS PUMP AND CLOSES VENT VALVE
LOW LEVEL SWITCH - CLOSES PUMP SUCTION LINE
TIMER AND PUSHBUTTON STATION TO START UNLOADING AND TO CUT MOTIVE AIR PRESSURE SUPPLY AFTER A PREDETERMINED NUMBER OF CARS HAS BEEN EMPTIED
GAS COMPRESSOR
WATER
INERT GAS QUENCH TANK
INERT GAS GENERATOR
FUEL GAS

UNLOADING
"CLOSED SYSTEM"

Figure 3

The loading system uses a pump (Figure 2) to provide the fluid pressure. Shutdown of the pump is actuated by a fluid level sensing unit in the last car. All displaced vapor is processed to the atmosphere through a flare or recycled to process storage. Each loading arm will be fitted with valves to prevent drip after being disconnected.

The unloading system in Figure 3 requires the generation of an inert gas, by combustion of fuel gas, for example, to insure non-contamination of the commodity. Further, the combustion gases are cooled and washed prior to being compressed and stored in pressure blimps. After the end connections have been made, the blimps are depressurized into the train. Control is based on a timed interval. A predetermined number of cars will be pressurized to 60 psi before the timer activates the inert gas shut-off valve. Liquid pressure is established in the suction vessel and pumping rate is determined by the suction pressure available to the pump. Expansion of the charged gas will continue to supply the necessary pump suction requirements until all of the cars are empty. The pump will be shut off by a low liquid level indication in the suction vessel. When the train is empty, the end connectors are removed.



PRESSURE CAR FOR INTEGRAL GAS SUPPLY

Figure 4

An alternative to the compressor in the loading facility layout and the compressor and blimps in the unloading facility layout is to use pressure cars to provide the necessary pressure for pumping (Figure 4). These pressure cars (from one to three cars) could be hauled as part of the unit train, thus saving the capital investment which that part of the facility layout requires.

The system is designed to maintain a flow rate of 3000 GPM at a maximum pressure of 60 psi in the tank cars. Under these conditions, a string of 20 tank cars can be loaded or unloaded with a single end connection. With a center point connection, 40 cars may be loaded simultaneously at this rate. Also, if the unit consists of 80 cars, two parallel strings of 40 cars may be loaded or unloaded simultaneously. If it is desired to reduce continuous track length, the number of parallel tracks can be increased to 4 so as to handle 4 strings of 20 cars. In this case, although the train switching time would be increased, "quick disconnect" type of connections would be provided between all cars that must be separated to minimize the additional time required for handling the larger number of connections.

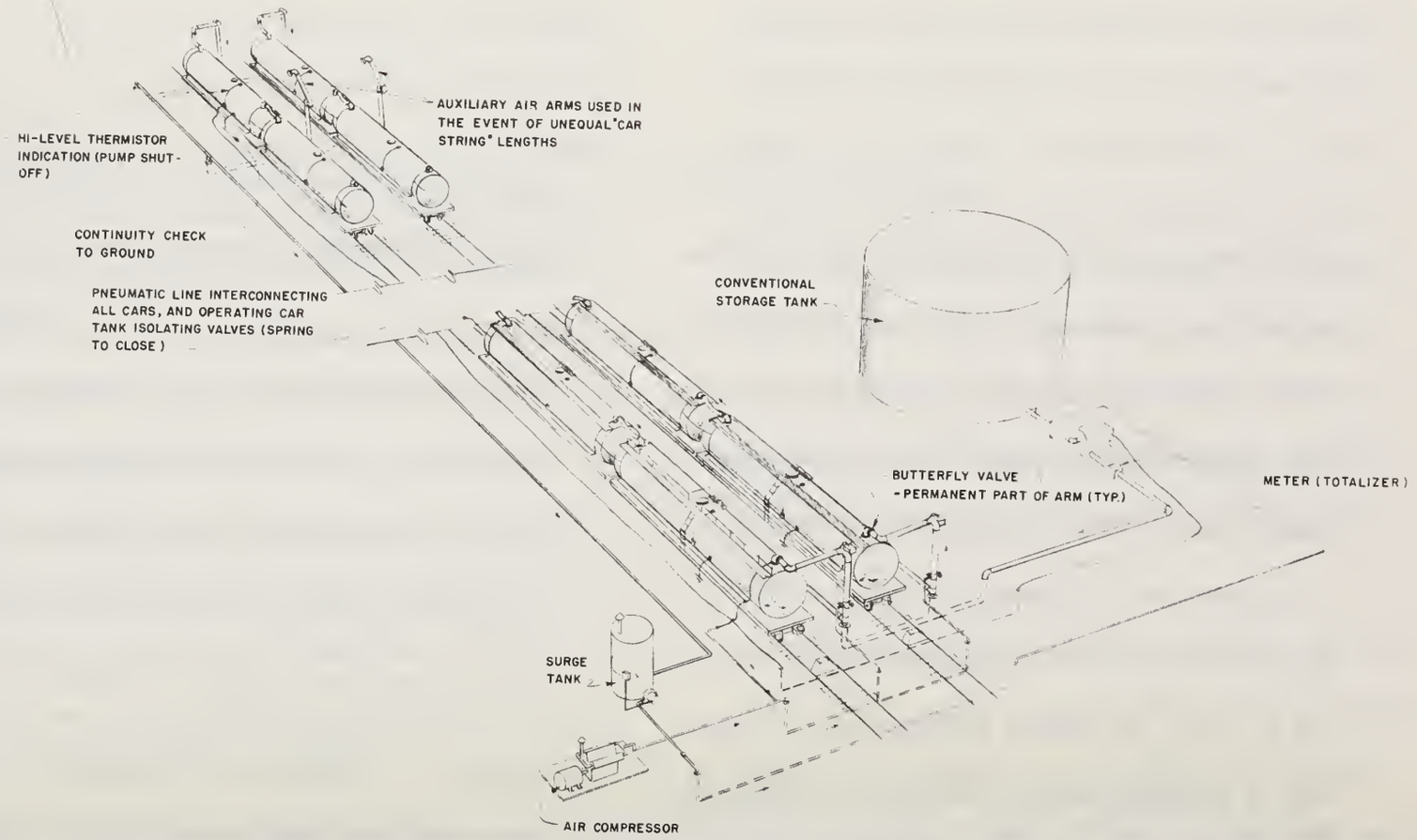
GATX estimates that an 80-car unit train can be loaded by a 2-man crew within an 8-hour shift period, from receipt of empty unit train to full-unit-train ready-to-go status. Unloading can also be accomplished within an 8-hour period.

SIMPLIFIED SYSTEM

The facilities for loading and unloading in the simplified system are shown in Figures 5 and 6. The concept is applicable for handling petroleum products of low volatility such as #6 oil.

As in the closed system described above, a pump provides the motive force in loading. The pump cut-off point is signalled by the sensing unit in the last car. Each loading arm (external hose connection) is fitted with valves to prevent drip after being disconnected.

The unloading facilities are simpler than those for the closed system. Air from the atmosphere is compressed to provide the necessary pressure. Car pressure is established by a pressure control valve. Pump start is based on a level established in the suction vessel pictured (Figure 6). Flow control is determined by suction pressure available to the pump. A predetermined number of cars will be pressurized to 60 psi before the timer activates the air line shut-off valve. Expansion of the charged air will continue to supply the necessary pump suction requirements until all of the cars are empty. The flow from the pump will be restricted when a suction pressure level drop is sensed in the suction vessel and the pump will be shut off when a low liquid level is indicated.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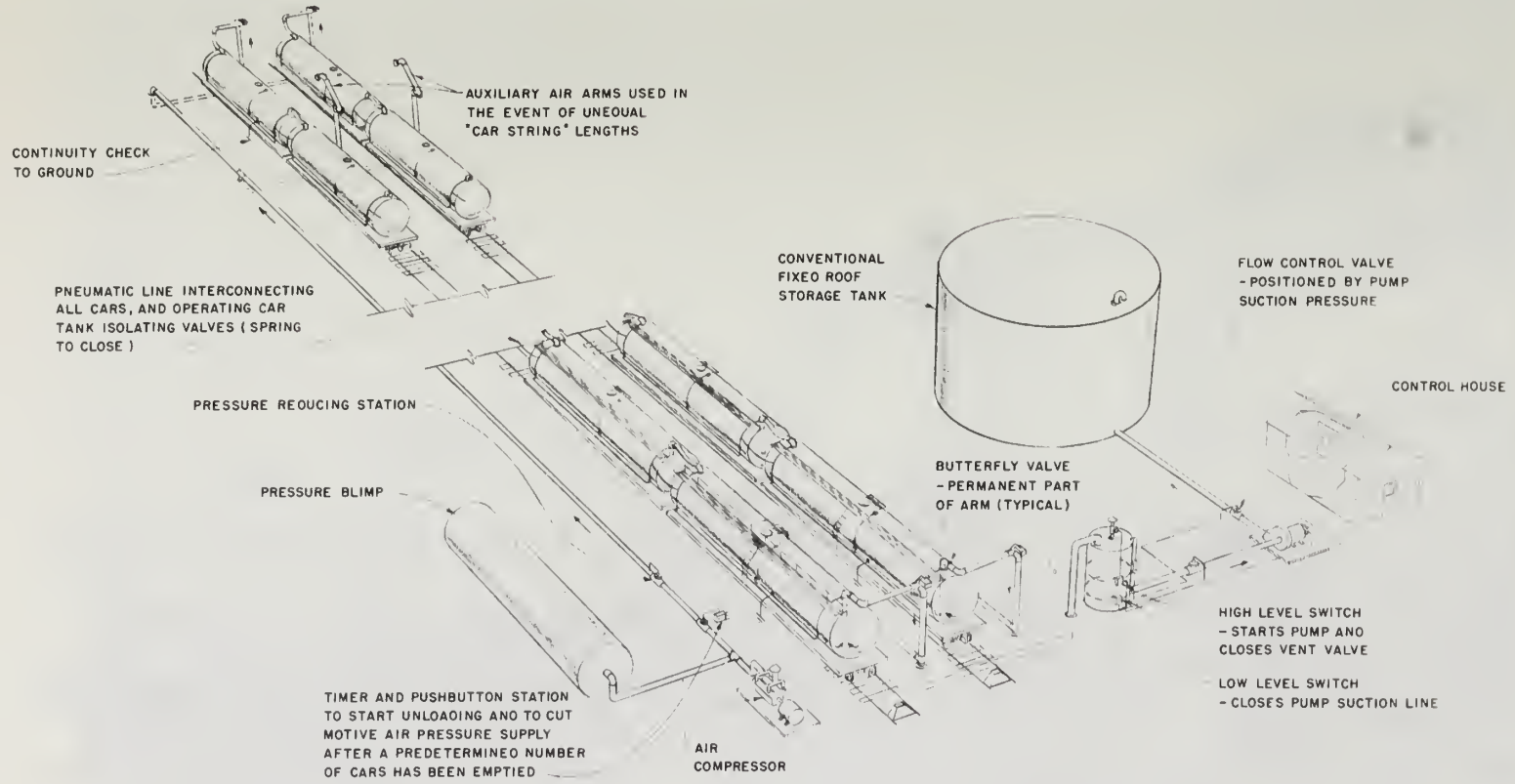
CONVENTIONAL STORAGE TANK
BUTTERFLY VALVE - PERMANENT PART OF ARM (TYP.)
METER (TOTALIZER)
SURGE TANK
AIR COMPRESSOR

LOADING
"SIMPLIFIED SYSTEM"

Figure 5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AIR COMPRESSOR

UNLOADING
"SIMPLIFIED SYSTEM"

Figure 6

The capital investment required for the facilities that make up this system are somewhat less than those required for the closed system. The time required for the sequences of operations in loading and unloading is approximately the same for this system as for the closed system.

INDIVIDUAL LOAD/UNLOAD

The cars in the unit train would also have the capability of being individually loaded through an open manway and individually unloaded through the bottom outlet, when modified with bolt-on/bolt-off hardware. In fact, it should be noted that the system cars are essentially standard DOT 111 A 100 W1 tank cars with additional top nozzles to receive the fittings for connection of the flexible pipes. Existing tank cars can be modified simply and then integrated into existing fleets or new system cars can be added to fleets without fear of obsolescence or special service restrictions.

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SUMMARY

The proper TANK TRAIN tank car is a DOT 111A100W-1, 23-150-gallon exterior coiled and insulated tank car with a 10-inch interconnecting hose system. This TANK TRAIN car is discussed later in this report. For study purposes, this car will lease for $480.*/per car, per month.

Two loading possibilities are available to ARCO:

CASE #1 - Loading in Long Beach

CASE #2 - Loading at one of several points east of Long Beach, eg., Colton, Corona, Indio, etc.

The MOPAC advised that a loop unloading arrangement at Midland, Texas would be favored by them for operational simplicity. We considered the land space constraints in Long Beach and the available space at Colton, Corona, Indio and Midland (additional loading sites proposed by the ATSF and SP), and developed the following Case #1 and #2 facility layouts and costs:

CASE #1

Loading - Three 36-car tracks, loading five 18-car strings simultaneously from the center of the facility, at a flow rate of 2,000 gpm per string (combined rate @ 10,000 gpm), in 3.5 hours. To be conservative we should allow 5 hours for loading.

* Actual quotations will be submitted upon request.

CASE #1

Unloading - Two 90-car loop tracks with the unloading system between the tracks, unloading each 18-car string simultaneously at 2,000 gpm (combined rate @ 10,000 gpm), in 3.5 hours. Again, we will use 5 hours in calculations.

CASE #2

Loading - Two 90-car loop tracks with the loading system between the tracks, loading each 18-car string simultaneously at 2,000 gpm per string in 3.5 hours. We will use 5 hours.

Unloading - Same as Case 1.

Three options were considered:

Case 1 & 2 Option A - 50,000 bbl/day

Case 1 & 2 Option B -100,000 bbl/day

Case 2 Only Option C -150,000 bbl/day

The facilities cost summary for each Case and Option is:

TABLE 3-1

Case	Capital Cost Facility	Operating Costs Option A	Option B	Option C
1.	$2,447,030	$167,083	$309,696	
2.	$2,566,340.	$165,114	$304,566	$444,364

The facilities costs are for both loading and unloading facilities, and include inert gas generators for the unloading operation and gas incinerators to conform with pollution regulations

during venting operations. Loading and unloading time requirements are five hours each. We used a 12-hour unloading period for the Midland, Texas proposals at the request of the MOPAC, to accommodate crew layovers, etc. The total facilities layover time is 17 hours. To determine unit train transit times, we used 21 mph as the constant train speed as a rule of thumb.

CASE #1

Case 1 considers the loading of TANK TRAIN in Long Beach. The ATSF and the SP have advised that each projects a 100,000 b/d limit for the crude oil they can transport out of the Long Beach port area, due to heavy traffic congestion in Long Beach.

The Santa Fe proposal will consist of several possible destinations from a loading point at ARCO's Carson Refinery in the Long Beach area, known as Watson on the ATSF. Most of the following tables examine the Santa Fe proposal from the position of cycle time and car requirements.

TABLE 3-2

CASE #1

Long Beach (Watson) to:

Destination	Roundtrip Miles	Days/ Cycle	Hrs./ Cycle	Cars Required* 50,000 bbl/day	Cars Required* 100,000 bbl/day
Amarillo	2,500	5.7(6)	136	594 (6 trains)	1,188 (12 trains)
Chicago	4,466	9.6(10)	230	990 (10 trains)	1,980 (20 trains)
Cushing	3,414	7.5(8)	180	792 (8 trains)	1,485 (15 trains)
Houston	3,634	7.9(8)	190	792 (8 trains)	1,584 (16 trains)
Kansas City	3,570	7.8(8)	187	792 (8 trains)	1,584 (16 trains)
Sweetwater/ Midland	2,944	5.9(6)	144	594 (6 trains)	1,089 (11 trains)

* Including a 10% spares contingency.
NOTE: In the calculation of "Days/Cycle", we rounded off this time period to the next highest number to arrive at a base number of required 90-car trains. The number of trains and cars required can be best determined when the shipper and a railroad develop a final operating plan.

The Southern Pacific's proposal to Midland, Case 1 considers a 2,274 mile roundtrip routing with an interchange with the Missouri Pacific Railroad at El Paso, Texas. The roundtrip transit and terminal time produces a 5.3 day cycle per train, creating a need for 6 TANK TRAIN unit trains for 50,000 b/d, and 11 TANK TRAIN unit trains for 100,000 b/d. ARCO will need approximately 594 TANK TRAIN cars at 50,000 b/d, (including 45 spare cars) and 1,089 TANK TRAIN cars at 100,000 b/d, (including 90 spare cars). The estimated average annual mileage each TANK TRAIN car will produce is 138,714 miles.

The loading and unloading facilities have been designed to accommodate a 90-car TANK TRAIN of five 18-car strings. These facilities can easily accommodate a 50,000 barrel capacity TANK TRAIN unit train. The capacity of each facility exceeds 200,000 b/d.

At 50,000 b/d, or 18,250,000 bbl/year, the projected TANK TRAIN System costs for Case #1 to Midland are as follows:

TABLE 3-3

50,000 b/d - CASE #1

Item	ATSF/bbl	SP/bbl
Annual Facilities Capital*	1.12¢	1.12¢
Facilities Operating	.92¢	.92¢
TANK TRAIN Lease Cost	18.75¢	18.75¢
High Mileage Cost	9.35¢	6.69¢
PROJECTED SYSTEM COST	30.14¢/bbl. (594 cars)	27.48¢/bbl. (495 cars)

* Excluding cost of capital.

TABLE 3-4

100,000 b/d - CASE #1

Item	ATSF/bbl	SP/bbl
Annual Facilities Capital*	.56¢	.56¢
Facilities Operating	.85¢	.85¢
TANK TRAIN Lease Cost	17.19¢	17.19¢
High Mileage Cost	8.57¢	6.13¢
PROJECTED SYSTEM COST	27.17¢/bbl. (1,089 cars)	24.73¢/bbl. (1,089 cars)

The ATSF considered additional destinations, which are presented in our cost projections in Table 3-5.

* Excluding the cost of capital.

TABLE 3-5

Watson to:

50,000 b/d

Destination	Cars	#1	#2	#3	#4	TOTAL
Amarillo	594	1.12¢	0.92¢	18.75¢	7.51¢	28.30¢
Chicago	990	1.12¢	0.92¢	31.25¢	13.78¢	47.07¢
Cushing	792	1.12¢	0.92¢	25.00¢	10.50¢	43.79¢
Houston	792	1.12¢	0.92¢	25.00¢	11.38¢	38.42¢
Kansas City	792	1.12¢	0.92¢	25.00¢	11.13¢	38.17¢

100,000 b/d

Destination	Cars	#1	#2	#3	#4	TOTAL
Amarillo	1,188	0.56¢	0.85¢	18.75¢	7.58¢	27.74¢
Chicago	1,980	0.56¢	0.85¢	31.25¢	13.77¢	46.43¢
Cushing	1,485	0.56¢	0.85¢	23.43¢	9.85¢	34.69¢
Houston	1,584	0.56¢	0.85¢	25.00¢	11.38¢	37.81¢
Kansas City	1,584	0.56¢	0.85¢	25.00¢	10.43¢	36.84¢

#1. Annual Facilities Capital Cost, excluding cost of capital.
#2. Annual Facilities Operating Cost.
#3. TANK TRAIN Lease Cost @ $5,760/car/yr.
#4. High Mileage Cost.

CASE #2

Case 2 considers the loading of TANK TRAIN at points east of Long Beach. The ATSF proposes a site at Corona, and the Southern Pacific suggests Colton or Indio. Other locations are possible and may bear study before a decision is made. The loading facility design can accommodate from 50,000 b/d to 200,000 b/d. The design is a loop design, and the unloading facility is the same as Case 1.

The Santa Fe proposals consist of the following basic data:

TABLE 3-6

Corona to:

Destination	Roundtrip Miles	Days/ Cycle	Hrs./ Cycle	Cars Required* 50,000 bbl/day	100,000 bbl/day	150,000 bbl/day
Amarillo	2,358	5.4(6)	129	594 (6 trains)	1,089 (11 trains)	1,683 (17 trains)
Chicago	4,324	9.3(10)	223	990 (10 trains)	1,881 (19 trains)	2,772 (28 trains)
Cushing	3,272	7.2(8)	173	792 (8 trains)	1,485 (15 trains)	2,178 (22 trains)
Houston	3,492	7.6(8)	183	792 (8 trains)	1,584 (16 trains)	2,277 (23 trains)
Kansas City	3,428	7.5(8)	180	792 (8 trains)	1,485 (15 trains)	2,277 (23 trains)
Sweetwater/ Midland	2,804	5.2(6)	144	594 (6 trains)	1,089 (11 trains)	1,584 (16 trains)

* Including a 10% spares contingency.

The Southern Pacific's proposals consist of the following basic data:

TABLE 3-7

Midland From:	Roundtrip Miles	Days/ Cycle	Hrs./ Cycle	Cars Required* 50,000 bbl/day	100,000 bbl/day	150,000 bbl/day
Colton	2,120	4.9(5)	118	495 (5 trains)	990 (10 trains)	1,485 (15 trains)
Indio	1,976	4.6(5)	111	495 (5 trains)	990 (10 trains)	1,386 (14 trains)

It should be noted that the Southern Pacific can provide proposals to destinations other than Midland.

At 18,250,000 bbls./year, the projected TANK TRAIN System costs for Case 2 to Midland are:

TABLE 3-8

50,000 b/d

	ATSF/bbl.	Southern Pacific Colton/bbl.	Indio/bbl.
Annual Facilities Capital**	1.17¢	1.17¢	1.17¢
Facilities Operating	.90¢	.90¢	.90¢
TANK TRAIN Lease Cost	18.75¢	15.62¢	15.62¢
High Mileage Cost	8.79¢	6.44¢	5.87¢
PROJECTED SYSTEM COST PER BBL.	29.61¢/bbl.	24.13¢/bbl.	23.56¢/bbl.

* Including a 10% spares contingency.
** Excluding cost of capital.

At 36,500,000 bbls/year, the projected TANK TRAIN System costs for Case 2 to Midland are:

TABLE 3-9

100,000 b/d

Item	ATSF/bbl	Southern Pacific Colton/bbl	Southern Pacific Indio/bbl
Annual Facilities Capital*	.59¢	.59¢	.59¢
Facilities Operating	.83¢	.83¢	.83¢
TANK TRAIN Lease Cost	17.19¢	15.62¢	15.62¢
High Mileage Cost	8.06¢	6.44¢	5.87¢
PROJECTED SYSTEM COST	26.67¢/bbl.	23.48¢/bbl.	22.91¢/bbl.

At 54,750,000 bbls/year, the projected TANK TRAIN System costs for CASE #2 to Midland are:

TABLE 3-10

150,000 b/d

Item	ATSF/bbl	Southern Pacific Colton/bbl	Southern Pacific Indio/bbl
Annual Facilities Capital*	.39¢	.39¢	.39¢
Facilities Operating	.81¢	.81¢	.81¢
TANK TRAIN Lease Cost	16.66¢	15.62¢	15.62¢
High Mileage Cost	7.81¢	6.44¢	5.48¢
PROJECTED SYSTEM COST	25.67¢/bbl.	23.26¢/bbl.	21.26¢/bbl.

* Excluding cost of capital.

The Santa Fe considered additional destinations, which are presented in the estimated cost projections of Table 3-11. On the following page Item #1 in the Table is the High Mileage Cost, #2 is the TANK TRAIN Lease Cost, #3 is the Facilities Operating Cost, and #4 is the Facilities Capital Cost.

TABLE 3-11

Corona to:

50,000 b/d

Destination	Cars	#1	#2	#3	#4	TOTAL
Amarillo	594	1.17¢	0.90¢	18.75¢	7.01¢	27.83¢
Chicago	990	1.17¢	0.90¢	31.25¢	13.22¢	46.54¢
Cushing	792	1.17¢	0.90¢	25.00¢	9.94¢	37.01¢
Houston	792	1.17¢	0.90¢	25.00¢	10.82¢	37.89¢
Kansas City	792	1.17¢	0.90¢	25.00¢	10.56¢	37.63¢

100,000 b/d

Destination	Cars	#1	#2	#3	#4	TOTAL
Amarillo	1089	0.59	0.83¢	17.18¢	6.43¢	25.03¢
Chicago	1881	0.59¢	0.83¢	29.68¢	12.56¢	43.66¢
Cushing	1485	0.59¢	0.83¢	23.43¢	9.32¢	34.17¢
Houston	1584	0.59¢	0.83¢	25.00¢	10.82¢	37.24¢
Kansas City	1485	0.59¢	0.83¢	25.00¢	9.90¢	36.32¢

150,000 b/d

Destination	Cars	#1	#2	#3	#4	TOTAL
Amarillo	1683	0.39¢	0.81¢	17.70¢	6.63¢	25.53¢
Chicago	2772	0.39¢	0.81¢	29.16¢	12.34¢	42.70¢
Cushing	2178	0.39¢	0.81¢	22.91¢	9.11¢	33.22¢
Houston	2277	0.39¢	0.81¢	23.96¢	10.37¢	35.53¢
Kansas City	2277	0.39¢	0.81¢	23.96¢	10.12¢	35.28¢

#1 Annual Facilities Capital Cost, excluding cost of capital.
#2 Annual Facilities Operating Cost.
#3 TANK TRAIN Lease Cost @ $5,760/car/yr.
#4 High Mileage Cost.

September 24, 1976

SO MUCH OIL WITH NO PLACE TO GO

THE ALASKA NORTH SLOPE
PETROLEUM ISSUE

1. BACKGROUND

In 1972, the Department of Interior issued an environmental Impact Statement approving the trans Alaska Oil Pipeline. In Volume 5, "Alternatives to the Proposed Action", the marine transport alternatives were discussed, starting on page 74. Figure A is the illustration from the EIS , showing the alternative marine routes. On page 78, the following statement is made.

> "The proposed submarines and semisubmersibles are quite large and at this point, are only conceptual, but they are probably technically and possibly economically feasible, providing certain navigational, terminal, technological and environmental difficulties are overcome."

In 1974-1975, the U.S. Maritime Administration contracted a detailed study of the Arctic crude oil submarine tanker system with a team of companies led by Newport News Shipbuilding. This 7 volume study, performed under contract No. 4-37032, examined,in detail, the navigational, terminal, technological and environmental issues, as well as the submarine system's economic feasibility in comparison with other alternatives. In the Fiscal Year 1975 annual report of the Maritime Administration, the following statement is made on page 32.

"Advanced Ship Systems:

> Another study examined the possibility of submarine tankers transporting petroleum products from Arctic oil fields and concluded that such vessels are technically and economically feasible."

2. GENERIC ARCTIC MARINE TRANSPORT SYSTEMS

The two generic Arctic marine petroleum transport alternatives are: 1) the icebreaking tanker, which must transit through the Northwest Passage because a trans polar route is technically infeasible. The Canadian Government has designated the waters of the Northwest Passage to be within the coastal zone of Canada and subject to their jurisdiction.
2) the submarine tanker which can, and preferably would, transit beneath the Arctic icecap as has been demonstrated to be routine by Naval submarines. This route through the international waters of the Arctic Ocean is beyond the Canadian jurisdiction. Either marine transport system would, if implemented, take the petroleum from its source on the edge of the Arctic Ocean to the principal U.S. market in the East by the shortest route, the sea route.

3. CURRENT SITUATION FOR ARCTIC PETROLEUM TRANSPORT TO MARKET

The Alaska North Slope initial oil production has been dedicated to a trans Alaska pipeline. Over its 680 mile length, it is proving to be the most expensive private construction project ever undertaken. It has already exceeded a cost of 7 billion dollars, which works out to over 10 million dollars a mile. Once the oil reaches the port of Valdez it must still be transported by sea to the lower 48 states and then further transported over land to market because too much oil will be landed in California for local consumption. This latter consideration is substantiated by recent FEA studies and admitted in Senate testimony on September 21, 1976. The State of California is taking the position that because of present air pollution levels, the Los Angeles basin should not be the point of entry of the "surplus" North Slope oil destined for another market to the east.

This has been reported in an article in the N.Y. Times on September 21, 1976, under the headline, "California Snubs Alaska Oil, forcing U.S. to reconsider." The California position is stated by Mr. Eli Chernow, special assistant to the Governor,

as: "SOHIO asserts its interest. The F.E.A. seems to accept that as in the national interest without questioning whether the national interest might call for something else." and, "What we have here is essentially a marketing problem for one company, SOHIO." This occurs because SOHIO has no west coast refineries and market presence, and even if they did, the market will not absorb the entire Alaska North Slope oil production rate.

An additional dimension is also added by the growing needs for oil to feed the refineries in the Northern Tier of states (Minnesota, Wisconsin and Michigan) as a result of a precipited decline in the schedule of delivery of Canadian (Alberta) crude oil across the border. The August 1976 F.E.A. study of this issue (Report FEA/G-76/350) identifies three alternative routes for new pipelines to satisfy this market from oil landed on the west coast. This market is not large enough to require all the west coast "surplus" of Alaska North Slope Oil. Therefore, there will inevitably be excess oil in the West and a deficit of oil in the east.

This west to east imbalance will only be further exacerbated with time under conditions of: 1) increased production from Naval Petroleum reserves in the west, 2) increased production of oil from the offshore leases off California, 3) Any production in the Gulf of Alaska and the offshore Cook Inlet area, 4) Increased production of Alaska North Slope oil from the Prudhoe Bay area fields, 5) production of oil from the National Petroleum Reserve Alaska (former NPR4) if this oil is sent southward across Alaska, 6) production of oil from Alaska Native Lands selections on the North Slope, 7) production from leases in the state and Federal offshore lands in the Alaska Outer Continental Shelf in the Beaufort Sea, Bristol Bay or Bering Sea Shelf.

4. CONCLUSION ON THE OIL MARKETING ISSUE

there is no way of getting the mounting surplus and impending deluge of U.S. oil on the west coast into the big east coast market inexpensively by the current transport systems logic as shown in Figure B taken from page 47 of the FEA Northern Tier study.

It is time to admit that a mistake was made in approving the Trans Alaska Pipeline as the sole means of getting at the Alaska North Slope petroleum resources. It is essential that plans be started immediately by the Federal Government to facilitate the startup of the Arctic Ocean direct marine transport route for Arctic oil. The only All-American route is the route under the icecap which has been shown to be technically and economically competitive.

5. BUT WHAT TO DO WITH TAPS?

This pipeline should be used for the initial oil production rate at 600 thousand barrels (bbl) per day. As quickly as possible the oil associated natural gas that comes out of the ground with this oil needs to be synthesized into methanol along with the associated natural gas liquids to make Methyl Fuel[R] . At the rate of roughly 0.35 bbl of Methyl Fuel per bbl of crude oil, the common carrier liquids pipeline would be used to send batches of Methyl Fuel to Valdez and thense to the California market in conventional tankers. With the addition of this second liquid, the pipeline throughput rises to 810 thousand bbl/day, reducing the cost of pipeline transport for each bbl by 1/3. Every bbl of Methyl Fuel can be marketed in California as a clean substitute fuel for natural gas and no California refining will be required.

In the longer term, the TAPS pipeline will turn into a transport system for more and more clean Methyl Fuel to California to reduce its air pollution levels,while the North Slope crude oil will be progressively phased into the Arctic Ocean marine transport system to the predominant east coast market.

In the short term, no SOHIO pipeline from California to Texas need be approved. U.S. flag tankers will be used to take the surplus oil to the Gulf Coast via the Panama Canal. Some of the Alaska North Slope oil will be sent to the Northern Tier states via displacement or via this Gulf of Mexico delivery of the Alaska North Slope Oil.

Methyl Fuel. T.M. Wentworth Bros. Cincinnatti, Ohio

6. SUMMARY

The oil and the gas exist together under the ground. It is the height of illogic not to consider their transport to market as components of an energy fuel transport systems approach. The west coast market needs large amounts of clean fuel. The east coast market needs large amounts of crude oil. There is a sensible approach to getting all the Alaska North Slope energy resources to the right markets, but is has to be implemented.

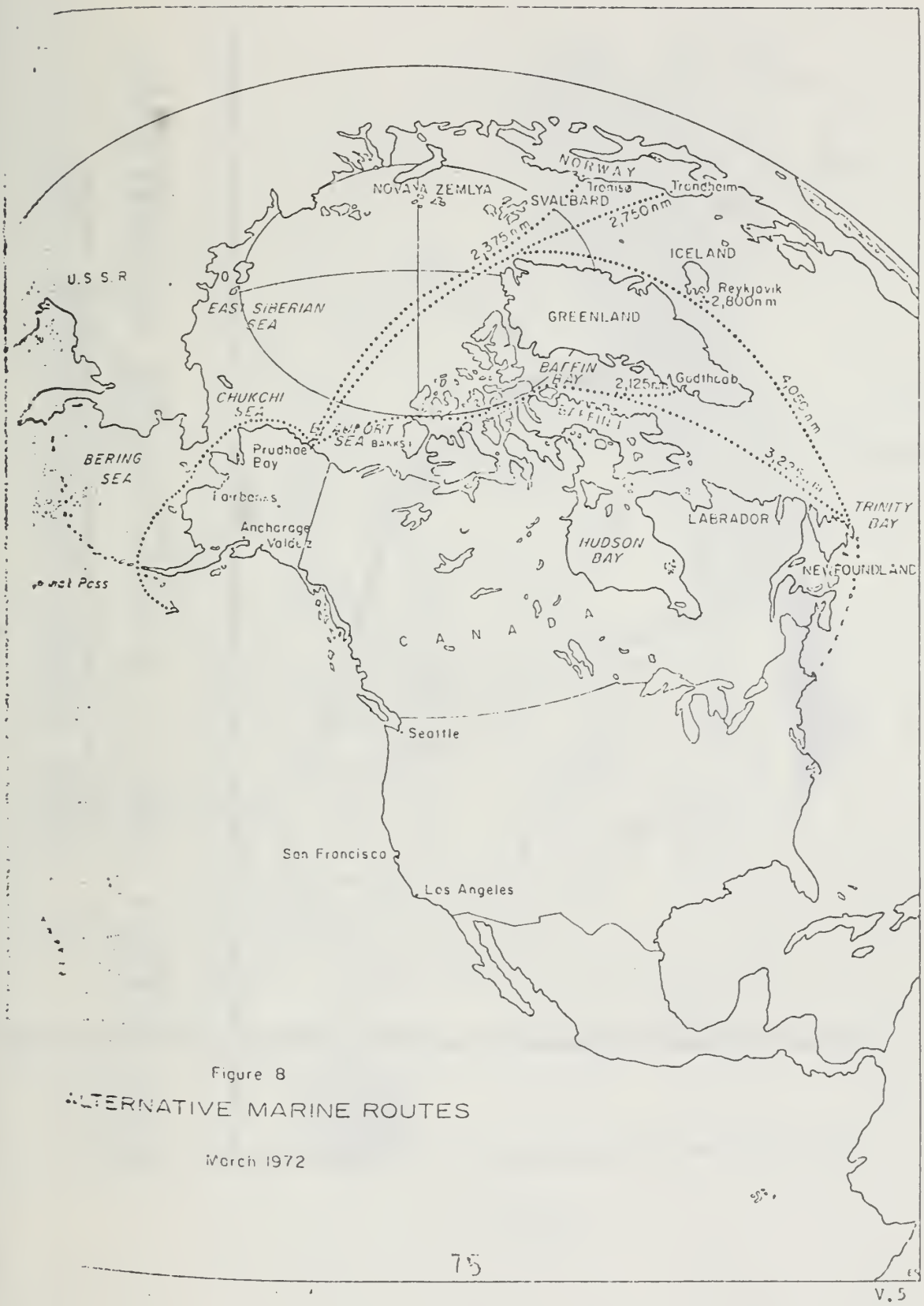

NORWAY
Tromsø
Trondheim
NOVAYA ZEMLYA
SVALBARD
2,750nm
2,375nm
ICELAND
U.S.S.R
Reykjavik
2,800nm
EAST SIBERIAN SEA
GREENLAND
BAFFIN BAY
2,125nm
Godthaab
CHUKCHI SEA
BEAUFORT SEA
BANKS I.
BERING SEA
Prudhoe Bay
Fairbanks
Anchorage
Valdez
LABRADOR
TRINITY BAY
HUDSON BAY
NEWFOUNDLAND
C A N A D A
Seattle
San Francisco
Los Angeles
Figure 8
ALTERNATIVE MARINE ROUTES
March 1972
75
V.5

FIGURE A

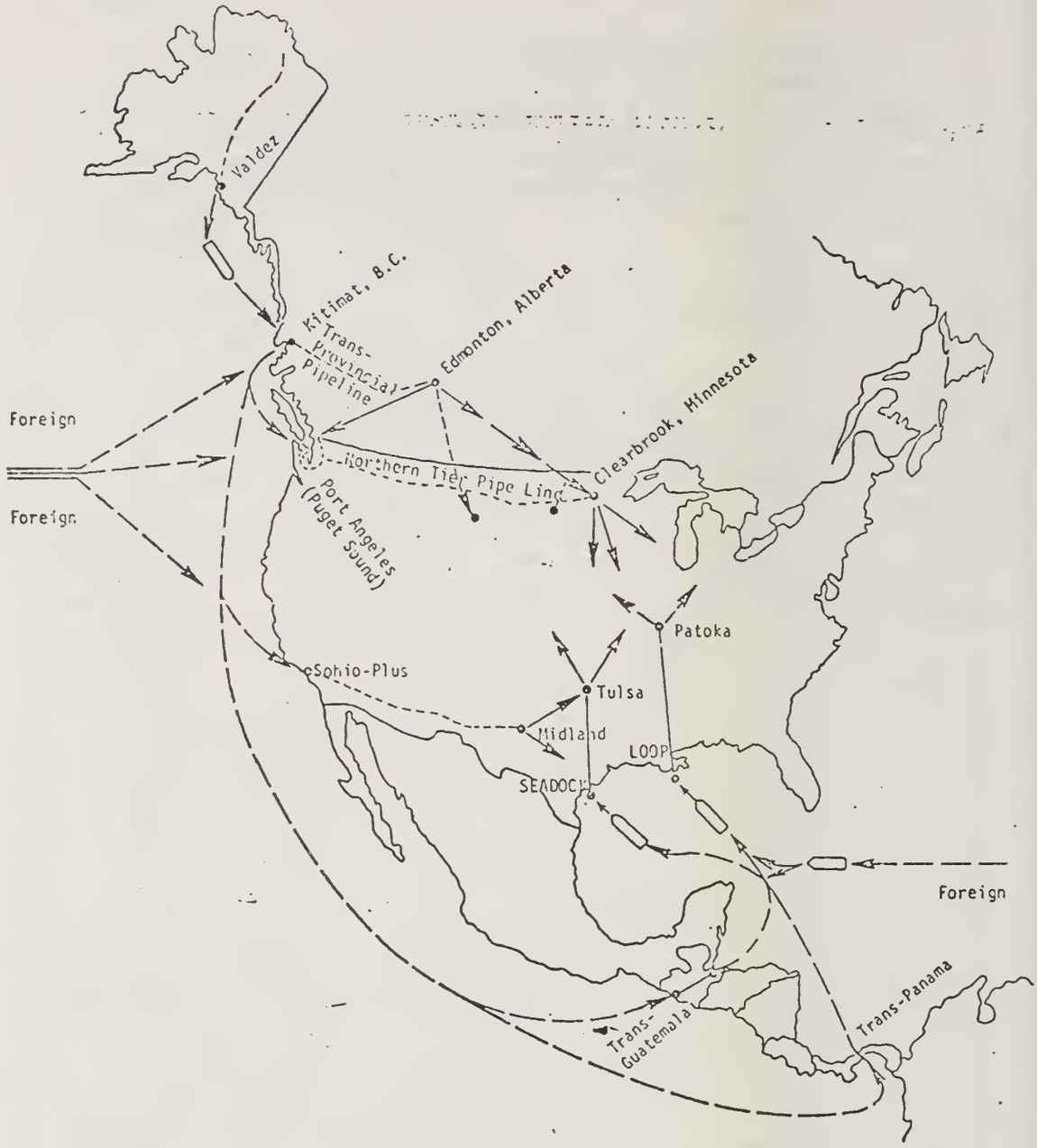


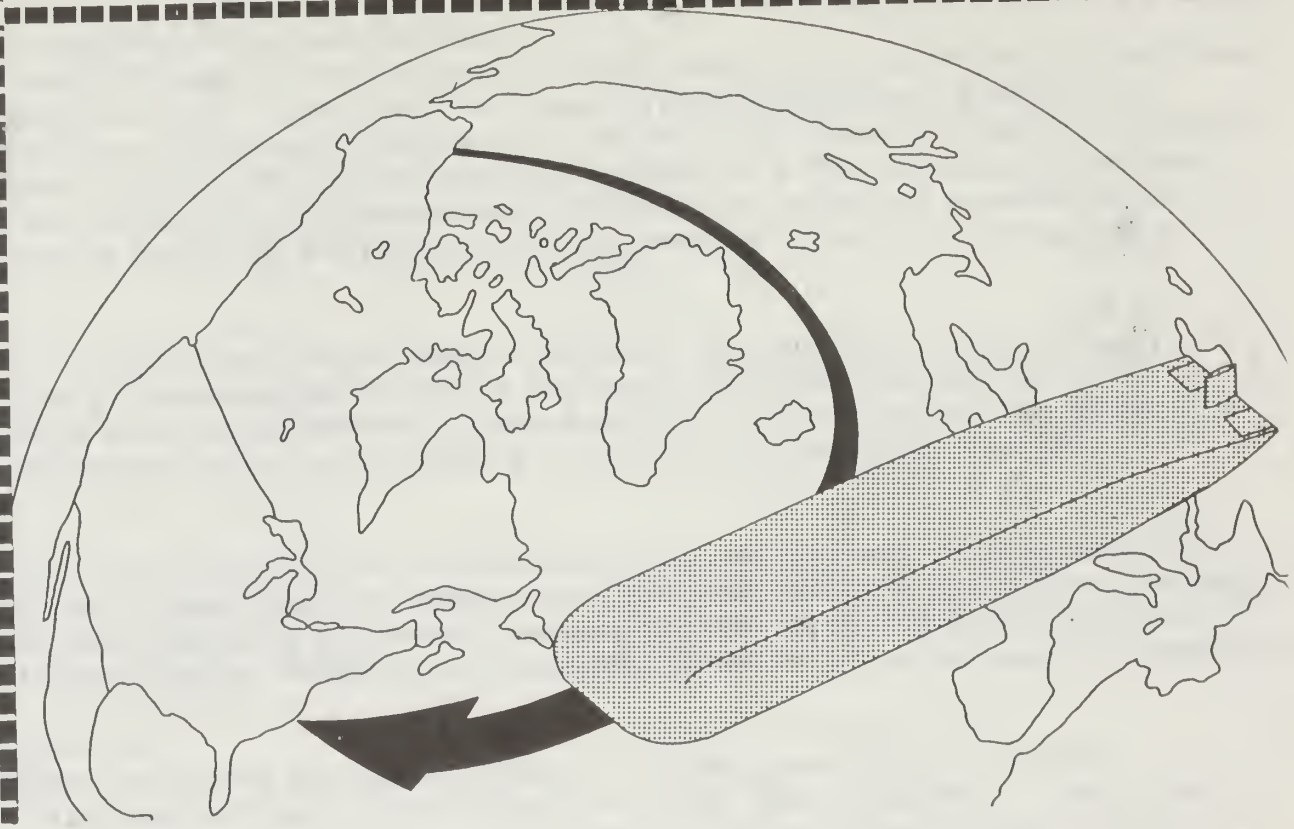
Figure 13-Crude Supply Alternatives for The Northern Tier States

47

FIGURE B

ARCTIC SUBMARINE TRANSPORTATION SYSTEM – 1975

VOLUME I-EXECUTIVE SUMMARY



PREFACE

Authorization - This study was authorized in June, 1974, by the U. S. Department of Commerce under contract No. 4-37032 with Newport News Shipbuilding and Dry Dock Company. The study work was under the auspices and technical direction of the U. S. Maritime Administration, Office of Commercial Development.

Study Team - The study was conducted by an industry team composed of Newport News Shipbuilding, Westinghouse Electric Corporation (Oceanic Division), Bechtel Incorporated and Mobil Shipping and Transportation Company, each team member undertaking the study work in its area of expertise. The study team was assisted by an Advisory Board composed of senior executives from the team member companies.

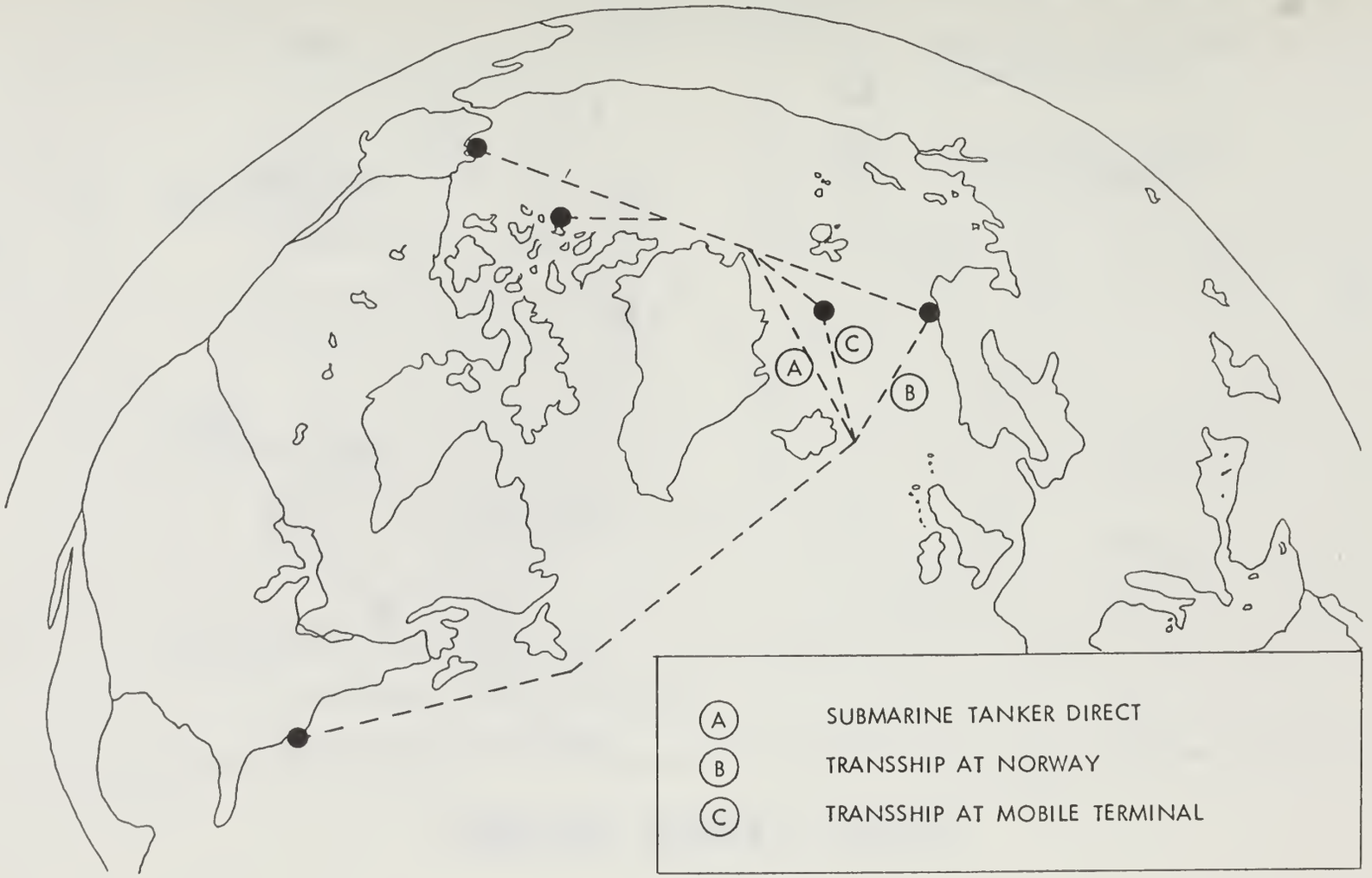
Objectives - The principal objectives of the study were to develop the conceptual design of a transportation system employing nuclear submarine tankers to deliver arctic crude oil to the U.S. east coast and to develop a plan for implementing such a system. Additional objectives were to minimize the system's impact on the environment and to evaluate its economic viability and operational practicality.

Scope - The study extended over a period of approximately six months. Study work consisted of system analysis and system evaluation and implementation planning for the total transportation system, supported by conceptual design and cost analysis of subsystems and analysis of overall system support requirements. Conceptual ship design was limited to the nucear submarine tanker (using a single B&W, CNSG power plant). The study included a limited analysis of arctic oil sources. Existing and proposed non-submarine delivery systems were also examined for purposes of economic comparison with submarine system designs.

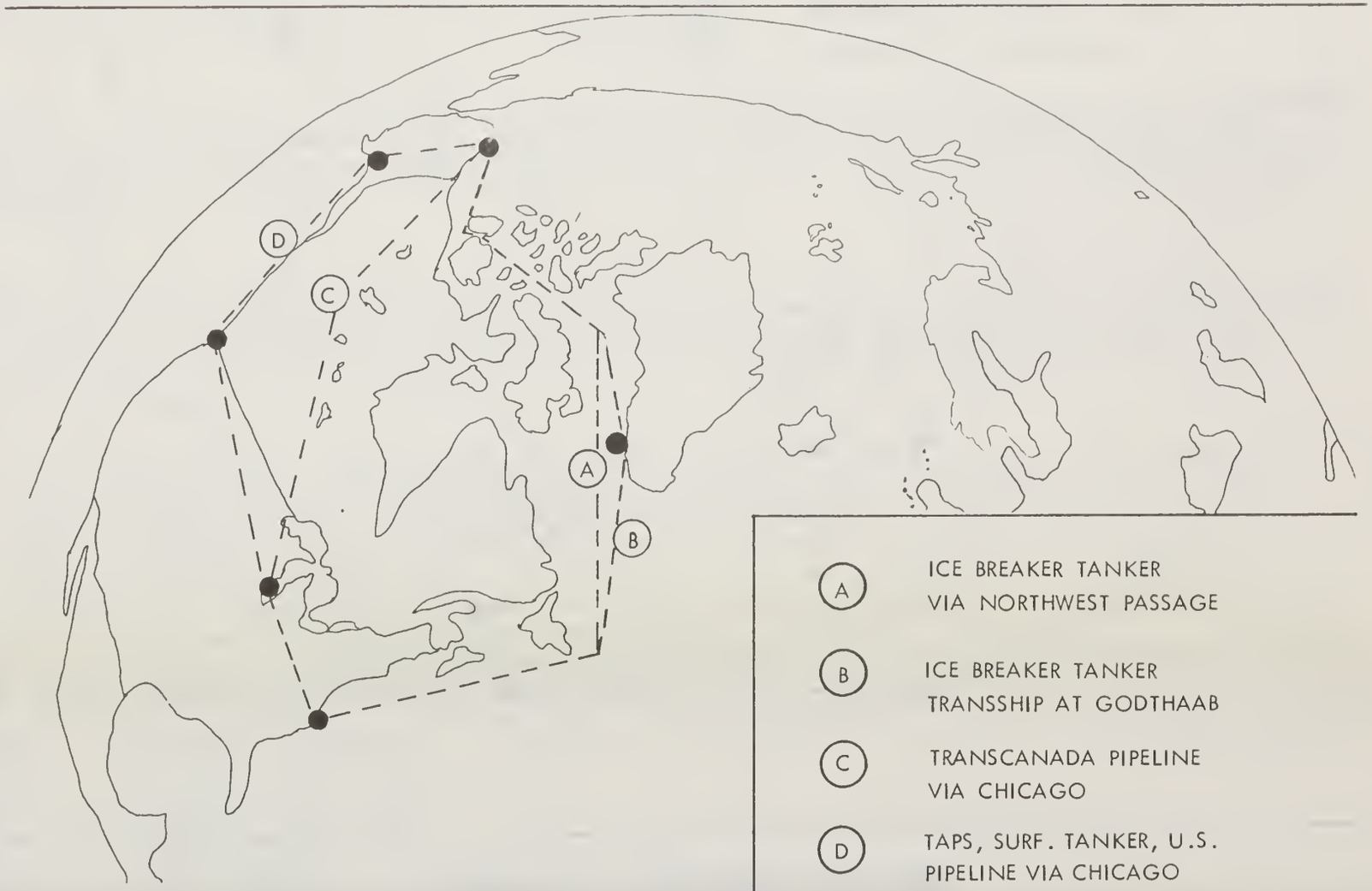
Results - Study results are presented in the following report volumes:

Vol. 1 - Executive Summary
Vol. 2 - Implementation Plan
Vol. 3 - Environmental Impact Analysis
Vol. 4 - Technical Analysis
Vol. 5 - Cost Analysis
Vol. 6 - System Development and Support Requirements
Vol. 7 - Personnel Acquisition and Training Plan

CANDIDATE SUBMARINE SYSTEMS



COMPETING DELIVERY SYSTEMS



(A) ICE BREAKER TANKER VIA NORTHWEST PASSAGE

(B) ICE BREAKER TANKER TRANSSHIP AT GODTHAAB

(C) TRANSCANADA PIPELINE VIA CHICAGO

(D) TAPS, SURF. TANKER, U.S. PIPELINE VIA CHICAGO

COMPARATIVE FREIGHT RATES

(PRUDHOE BAY SOURCE)

SUBMARINE TANKER	$ PER BBL
PRUDHOE TO CAPE CHARLES	3.60
TRANSSHIP AT NORWAY	2.64
TRANSSHIP AT "FROST"	2.33
ICEBREAKING TANKER	
PRUDHOE TO CAPE CHARLES	3.08
TRANSSHIP AT GODTHAAB	2.87
PIPELINES–PRUDHOE TO PHILADELPHIA	
TAPS/TRANSSHIP/ TRANSCONTINENTAL	4.47
TRANSCANADA VIA CHICAGO	4.55

"ARE THERE ANY QUESTIONS?"

Q - Why hasn't the arctic submarine tanker system been previously implemented?

A - Presumably, because its technical feasibility and economic viability have not been apparent to prospective users. Compared with pipelines and surface tankers (even arctic pipelines and icebreaking surface tankers) the submarine has been looked upon as being "unnatural". In reality, its characteristics are uniquely compatible with the arctic transportation environment.

Q - Is it practical to design the system for a lower throughput?

A - Reduction in system throughput results in proprotionate reduction in submarine costs and substantially lower capital investment. For the all-submarine system freight rates would not increase substantially until throughput is reduced by 50 to 60%.

Q - What is the system sensitivity to the use of larger or smaller submarine tankers?

A - This sensitivity was not specifically addressed in the study. Previous studies have shown RFR to be sensitive to ship size and relatively insensitive to ship speed (in the range of 20 knots and above). The two million barrel capacity approaches the practical size limit for existing U. S. construction. Also this size yields a 20 knot service speed which appears appropriate for a large vessel operating under ice.

Q - What effect will escalation have on system economics?

A - Economic results have been based on constant 1975 prices. Escalation of capital and operating costs will require a corresponding increase in net revenues in order to achieve the projected rates of return.

Q - Can the system be used for the transport of LNG or methanol?

A - The proposed design can accommodate liquids of the specific gravity of methanol. The economic consequence has not been analyzed but would be less favorable than for crude oil because of methanol conversion costs and lower net revenue. The proposed design is not suitable for LNG; however, such a design is feasible.

Q - What are the problems with regard to international jurisdiction?

A - Transshipping at foreign ports will entail customary foreign controls. "Direct" systems or those transshipping at sea are Jones Act systems subject only to United States and international law. IMCO regulations would be applicable and any international "coastal zone" agreements would also apply.

Q - How can the arctic terminal be designed without specific knowledge of geological and bathymetric conditions at the site?

A - Detailed surveys at all sites are required. At the arctic site this will be time consuming and costly because of the short open water season, the remoteness of the location and the severity of working conditions.

Q - Is the 80 foot diameter pressure hull practical to construct?

A - The 3-1/4 inch thick pressure hull can be fabricated using existing techniques. However, reduction in hull diameter and thickness would make construction simpler and less costly. The use of one or more smaller reactors would permit this.

Q - Does the single nuclear reactor provide adequate ship and personnel safety for the under-ice transit?

A - In the proposed design an independent emergency propulsion plant provides a 90 mile "search" range at slow speed to enable the submarine to reach a suitable location for penetrating the suface for access to air, and for radio communication. Each submarine is also equipped to "dock" with a disabled one for salvage and rescue purposes. Use of two reactors would eliminate the need for an emergency propulsion system.

Q - Is timely AEC approval of the nuclear power plant expected?

A - This depends on the quality of the design for this commercial ship application. The B&W, CNSG design has been actively supported by MarAd and has been under preliminary AEC approval scrutiny for some time. Continued government/industry support of nuclear power plant development is required to insure timely approvals.

Q - Will sea and weather conditions at FROST adversely affect the system's ability to maintain design throughput?

A - Detailed survey of this area has not been made; however sea and weather conditions at the edge of the ice pack are expected to be much more favorable than those in the open sea. This question requires detailed investigation in the design of the FROST transshipping system.

Q - What degree of reliability can be expected in shore-to-ship sonar communications under ice?

A - Sonar communication at and near the terminal will be highly reliable. Along the under-ice route, however, continuous shore-to-ship communication is impractical due to own-ship noise at high transit speeds. While shore-to-ship communication is not critical, it is considered desirable and may be achieved on a intermittent basis by means of sonar transponders placed along the route and linked to low frequency shore-based transmitters.

Q - What is the potential for improved system performance?

A - System design has been based on existing U. S. technology and ship construction. These factors are not expected to change appreciably in the near term. While refinements can be achieved in the design of the operational system, they are not expected to have a significant effect on system efficiency. In the long term, however, nuclear powered submarine systems could play an important role in the development of all offshore resources.

ROUTING AND TRANSMITTAL SLIP		ACTION
1 TO *(Name, office symbol or location)*	INITIALS	CIRCULATE
Bill	DATE	COORDINATION
2	INITIALS	FILE
	DATE	INFORMATION
3	INITIALS	NOTE AND RETURN
	DATE	PER CONVERSATION
4	INITIALS	SEE ME
	DATE	SIGNATURE

REMARKS

Here are copies of the only testimony I could locate giving FEA's position on the use of alcohol as a motor fuel. It would appear that we have not ruled it out altogether.

Do NOT use this form as a RECORD of approvals, concurrences, disapprovals, clearances, and similar actions

FROM *(Name, office symbol or location)*	DATE
Lisle Reed, Director Office of Oil and Gas Federal Energy Administration	8/12/76
	PHONE 961-6037

OPTIONAL FORM 41
AUGUST 1967
GSA FPMR (41CFR) 100 11.206

c48—16—81594-1 552-103 GPO 5041-101

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

Statement of James R. Gill
Associate Assistant Administrator
Energy Resource Development

before the

Subcommittee on Energy Research, Development and Demonstratio

of the

House Committee on Science and Technology

June 17, 1975

METHANOL

Background

The American public in increasingly hearing of a new glamour fuel, methanol. Enthusiasts at such august universities as the Massachusetts Institute of Technology claim it as an excellent fuel for automobiles. Utilities are interested in methanol as an energy source to produce peak load electricity. Methanol can be produced from municipal wastes and thereby change garbage from a dumping expense into a source of city revenue. Several states are investigating the possibility of making methanol from forest wastes. Agricultural residue - rice hulls, peanut shells, any cellulose substance - can be converted to methanol. On top of all this, methanol is a clean, nonpolluting fuel without so much as a faint odor when it burns at atmospheric pressure.

Well, perhaps it's about time that methanol came in for a little public recognition. It's been around for a couple of hundred years. Although, of course, during most of that time it was just wood alcohol. It has, in the past, powered automobiles. In fact, most racing cars today are designed to use the more thermally efficient methanol rather than gasoline. It has been burned as an industrial fuel. Germany used it to fuel part of her war machine during the two world wars when the Allied naval blockades cut her petroleum supply. Methanol has been used as a chemical base stock ever since the start of the chemical industry. Thus, methanol is by no means new as a commercial or

79-745 O - 76 - 20

industrial product. Despite claims by its most enthusiastic supporters, methanol is certainly not the instant solution to our present energy shortage nor is it likely to really be an important element in the final solution. The supply will probably prove too limited for that. Certainly the increasing cost of other fuels will make methanol more attractive than in the past. Certainly more cities will convert garbage into methanol. Certainly more methanol will be produced from agricultural wastes and forest residues. As methanol is increasingly produced and consumed, new uses will be found and demand for it will grow.

Sources of Methanol

It can be produced from any carbonaceous material. In essence, a carbonaceous material is something that grows, such as trees and grass and animals, or the remains of things that once grew, which includes coal, petroleum and natural gas. Methanol can, of course, also be made of any product manufactured from a carbonaceous material. If your chair is wooden, you are sitting in a potential source of methanol. Your cotton shirts, leather shoes, breakfast eggs and morning newspaper all could serve as sources of methanol.

Almost all methanol now produced in the United States, about 65,000 barrels a day, is made from natural gas and is used in the petrochemical industry. The conversion is accomplished when methane, or natural gas, reacts with steam and oxygen to yield products which can

then be reformed, in the presence of suitable catalysts, into methanol and carbon monoxide. As the price of natural gas increases other sources will be found for this chemical grade methanol. Seattle has recently completed plans to produce a superior grade product from its garbage. Any other city willing to make the large investment necessary will find a growing market for methanol of the purity demanded in the chemical field.

Little or no fuel grade methanol is produced in the United States at this time. The Federal Energy Administration (FEA) has underway, and almost completed, a study which investigates the feasibility of converting the Alaskan north slope natural gas into fuel grade methanol and bringing that to the lower 48 states in the oil pipeline as an alternative to building a gas pipeline through which the gas would be moved. The idea is to use the excess capacity of the crude oil pipeline, now under construction, rather than lay an additional pipeline which would be required if natural gas is to be transported. While the methanol concept appears quite feasible from a technical standpoint it perhaps will not be satisfactory from an economic view. Of course, it is natural gas that the United States is short of presently, not methanol. However, if it turns out that receipt of the Alaskan natural gas will be for some reason long delayed in the lower 48 then that energy might land in California as methanol. This could in time cause the daily supply to increase to 400,000 barrels a day, which would spur a methanol market into being in short order.

The gas-to-methanol conversion could ideally be used in remote oil fields in hostile environments, enabling producers to get both the oil and gas moved to market using only one pipeline when the economics of the situation do not justify two pipelines. It should be mentioned that an irreversible energy loss of approximately 40 percent is encountered when gas is converted to methanol. Under ordinary circumstances, this loss will mean that gas energy will be marketed as a gas, but in locations where pipeline construction is difficult and expensive, the methanol concept might prove advantageous.

The State of California presently has under consideration a plan to make a fuel grade methanol from forest wastes. In order to provide a ready market for the large amounts of methanol expected from such an undertaking its use as a component in all gasoline sold in the state would be mandated by law. A gradual increase of the methanol component is envisioned: 5 percent by 1980, 10 percent in 1985 and 15 percent in 1990. Maine has also recently begun to eye the possibility of producing methanol from its forests.

The production of methanol from municipal garbage seems to have an instant appeal to almost everyone. Nobody likes the idea of waste, landfills are unsightly and garbage is regarded as free. Energy from this source will certainly be increasingly utilized in the future, but it will not result in the production of much methanol. Municipal wastes can be burned alone, or better, mixed with coal

and the heat directly used to produce electric power or for some other industrial use. This is being done today in Baltimore. Or, it can be made into methane and piped to some other location for use as a heat source. Charleston, West Virginia, has an experimental plant accomplishing this. Most cities will find it more profitable to produce heat that is directly used or to produce methane for pipeline transfer than to take the further, energy losing step to make methanol. Seattle, in her special circumstance of being in an area which has adequate hydroelectric power and no nearby coal mines, opted for methanol. A few other cities will do the same, most will not.

Methanol can be produced from crude oil or from coal. There appears little purpose in doing so, however, We are so short of crude oil in this country that we have to import a large percentage of our needs. There is little purpose in making imported crude oil into methanol when it can better be made into petroleum products which are required for existing requirements. Coal will some day, and probably soon, be successfully liquefied into a commercial product. Coal liquefaction will, however, result in a synthetic crude oil and not methanol.

Another possible source of methanol is imports. At this time, the United States is a net exporter of methanol, shipping out 3,500,000 barrels in 1974 while importing only 425,000 barrels. However, if domestic demand grows in the future, this situation could be reversed and we could begin to bring in large amounts of methanol.

Presently huge volumes of natural gas are being flared in the Arabian fields because there is no economical way to get that energy to a market. Efforts are underway to collect this gas and use it as a basis of a petrochemical industry in the Mideast. Methanol in quantity might be a by-product of such a development and its export by the Arabians to the United States a possibility. Methanol from foreign sources would probably help rather than hinder American methanol production as adequate supply of the product is necessary to whet demand and the demand is likely to grow faster if a steady supply is assured. But importation of methanol in meaningful quantities is far from assured at this time.

Apparently, then, the use of methanol in the United States will be restricted by limited production.

Uses of Methanol

Enthusiasts advocating use of methanol as a component of gasoline cite many advantages to be gained, such as decrease in pollutants in automotive exhausts, increase in engine efficiency and so on. All such claims are disputed by other experts who are just as technically qualified to judge the matter. In short, there are still many pros and cons - many uncertainties - in the use of methanol as a motor fuel component. During the sixty to seventy-five years of development of mass produced automobiles the combustion engine has been matched

with increasing precision to gasoline by car manufacturers and gasoline has been as carefully matched to the automobile engine by the petroleum refiners. The old Model T Ford could use about any liquid that would burn, from cleaning fluid to kerosene. The new high compression engines in the family car of today will efficiently use only the products within a narrow range of petroleum distillation. While new engines can be designed to use a methanol/gasoline blend and perhaps old engines converted to such fuel, difficulties will undoubtedly be encountered during the initial years of the changeover. For example, there is evidence that methanol, even methanol in solution with gasoline, might dissolve the fuel tank liners in modern cars. Many plastic gaskets used in gas lines might similarly be eroded by a fuel that is partly alcohol. These problems, and others, are of course not insoluble but there is reason to wonder if it is worth the effort to make the switchover, particularly as methanol might better be put to other uses. Indeed, if methanol is ever produced in such quantities as to make its use in transportation desirable it probably would be better utilized as a pure fuel in captive fleets, such as taxis, delivery vans or garbage trucks. Such fleets could rather easily be provided with a special engine design to use pure methanol. Other modifications would be required. An example

would be the necessity of a double sized fuel tank as methanol has only 50 percent of the energy of gasoline by volume. If methanol should ever become so plentiful and cheap as to make it a more economical alternative for gasoline its use in fleets would be the logical, and voluntary, choice by fleet owners. And the average car owner would be spared the dangers of using a modified fuel.

Presently there is little or no methanol being burned as an industrial fuel. Price and supply have negated such utilization. If methanol was plentiful and inexpensive in comparison to other forms of energy it would make an excellent fuel to be burned under a boiler, where it is essentially nonpolluting. Methanol can be transported in present day petroleum carriers, pipeline, railcar or truck, and its uncontrolled burning, as in an accident, is more easily controlled by firefighters as it combines easily with water and the resulting mixture become nonflamable. Thus it could be utilized even in home heating in place of the light distillate fuel oil that is most commonly used.

Predictions, especially predictions in developing fields such as energy today, are likely to prove less than accurate. But if a prediction for methanol's future is to be made at this time it would appear that its prime use will be as a fuel for combustion turbines powering generators designed to handle peak load electric power demand. Combustion turbines are close cousins to the jet engines used on aircraft.

.... (Subsequent pages are missing from this copy)

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JOHN R. HALL
Executive Vice President

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September 13, 1976

Senator Henry M. Jackson
137 OSOB
United States Senate
Washington, D. C. 20510

Senator Adlai E. Stevenson, III
456 OSOB
United States Senate
Washington, D. C. 20510

Senator Warren G. Magnuson
127 OSOB
United States Senate
Washington, D. C. 20510

Dear Senators:

The attachment is a response to your questions concerning potential problems associated with the delivery of crude oil from Alaska's North Slope dated August 23, 1976. You asked that my response address specifically Question IV, and that my response also should cover any other questions about which I have information. I have placed my response to Question IV at the front of the attachment and my responses to Questions I, II, III, and V appear after the response to Question IV.

It is hoped that the attachment will be useful in your deliberations concerning the surplus of Alaskan oil on the West Coast. Please do not hesitate to contact me again if I can provide additional information or if clarification of these remarks is required.

Sincerely yours,

John R. Hall

JRH/eb
Attachment

QUESTIONNAIRE

Potential Problems Associated with the
Delivery of Crude Oil from Alaska's North Slope

Section IV - A, B, C - Evaluation, comparison, status, and implementation of the proposed responses to deal with the projected surplus of North Slope crude oil on the West Coast.

Before beginning a comparison of the various alternates proposed to transport excess volumes of Alaskan crude oil from the West Coast to other major refining centers in the lower forty-eight, it probably would be useful to explain that the West Coast excess crude oil problem is a separate and different issue from the declining crude oil supply problems being faced by Northern Tier refineries. The West Coast crude oil surplus results from equipment constraints that limit West Coast refineries' ability to process the entire volume of heavy, high sulfur oil that will be produced in Alaska. In contrast, the declining supply of crude oil to Northern Tier refiners results from the Canadian Government's decision to reduce crude oil exports into the United States in order to conserve their declining reserves. The difference in these two issues and, in particular, the nature of the Northern Tier supply problem will be discussed in greater detail later in this report. Suffice it to say at this point, the two problems do have a common denominator because a portion of the West Coast surplus could serve to augment the declining supplies in the Northern Tier.

After reviewing your nine alternate solutions to the West Coast crude surplus issue, it becomes apparent that some type of grouping is needed if the proper perspective of the various alternates is to be maintained. It would be an

error to view the nine alternates as being comprehensive or as being equal.

First, alternates one and two, the Kitimat Pipeline and the Northern Tier Pipeline respectively, are proposals to solve the declining crude oil supply problems now threatening the very existence of Northern Tier refineries. Either of these proposals will provide Northern Tier refineries access to world crude oil supplies which would include Alaskan oil. The amount of Alaskan oil that can be expected to move over either of these systems is related to the hardware constraints of Northern Tier refineries in the same way as the volume of Alaskan oil that can be consumed on the West Coast is related to refinery capability. We estimate that about 200,000 barrels per day of Alaskan oil could be utilized by Northern Tier refineries today. This figure is not limited by pipeline design, but it is directly related to refinery capability. The remaining 100 to 500,000 barrels per day of crude oil that would be transported by either of these pipelines probably would be foreign, light, low-sulfur crude oils. We believe these two proposals to be mutually exclusive, and hopefully, the successful project will be the one that can perform its task at the least cost.

Alternate three in your alternate list, the Sohio project, is directed at solving only the West Coast crude oil surplus problem. The project will be capable of moving 500,000 B/D of excess Alaskan oil to the South-West, but unfortunately, the project cannot solve the Northern Tier supply problem.

Alternates four and five, the Panama routes, are not viewed as practical or as competitive with alternates one thru three because they require the use of small

inefficient tankers or they involve extremely long tanker hauls to reach major refining centers. Furthermore, these alternates offer nothing to the Northern Tier. Alternate five, the Panama Canal, may be a practical short term partial solution to the West Coast surplus problem if construction delays are encountered in alternates one thru three.

Alternate six, retrofitting existing West Coast refineries, cannot be accomplished by the time the crude oil excess developes on the West Coast. This alternate could be viewed as a possible long term solution, but many factors, such as demand for products refined from Alaskan oil and environmental issues associated with additional refinery construction and operation, would need resolution before this alternate would prove viable.

Alternate seven is not feasible because desulfurization of whole crude oil is not a proven technology.

Alternate eight, shutting in Alaskan production until West Coast demand and refining capacity are in place, is illogical because the crude oil supplies are sorely needed in the lower forty-eight states now and because viable alternates are available to take full advantage of the production avails in Alaska.

Alternate nine, exchanges with foreign countries, is viable and logical as a short term remedy to the crude oil surplus problem. Further discussion of this alternate will be provided later.

In summary, alternates one, two, three, and nine are viable and practical. The list of viable alternates probably should be expanded to include

reversal of the Transmountain Pipeline, construction of a new pipeline system from Cushing, Oklahoma to St. Paul, Minnesota, and expansion of CAPLINE and subsequent extension into Chicago and St. Paul.

Let's now turn to a brief description of the Kitimat Pipeline project and a review of its current status. The Kitimat Pipe Line study group envisions constructing a pipeline from Kitimat, British Columbia, to Edmonton, Alberta, where it will tie into the existing Interprovincial and Rangeland Pipe Line systems. Approximately seven hundred miles of new pipe will be installed and about fifty miles of idle Trans Mountain equipment will be utilized. An alternate route is under consideration at this time that would utilize 300 miles of existing Trans Mountain pipe. This new route would reduce the new construction distance to only 450 miles, and it would reduce the expected capital cost by about one-third.

Kitimat is located 60 miles from the Pacific Ocean at the end of a deep-water fiord, where it will be possible to construct a crude oil terminal capable of receiving Alaskan or foreign crude oil by very large crude carriers. Kitimat is an industrial town and there is already significant movement of bulk carriers into the Kitimat Harbor. The pipeline will be thirty inches in diameter and will be designed for an initial thruput of 300,000 barrels per day and an ultimate capacity of 750,000 barrels per day without looping.

Numerous sites were considered for the western end of the pipeline project and many were rejected on a judgmental basis. After careful evaluation, Kitimat was the site selected because it best satisfied all the criteria used for site selection.

The Kitimat Pipe Line study group consists of ten companies, including eight U. S. petroleum refiners or their Canadian affiliates and two Canadian pipeline companies. This study group was formed several months ago to evaluate the environmental, engineering, economic, political, and legal aspects of the Kitimat Pipe Line. Each company committed $50,000 and the time of personnel knowledgeable in each respective area to expedite these studies. The preliminary engineering and economic feasibility studies have been completed, and they indicate that the pipeline will cost approximately $470 million. An average tariff of 65¢ per barrel of crude oil transported will be required over the project life to provide a 9% return rate on capital employed in the project.

In-depth studies have been made of possible environmental and other problems associated with the Kitimat Pipe Line and we are optimistic that we can obtain approval for the project since it offers many benefits to Canada. Preliminary discussions about Kitimat have been held with public officials of Canada and British Columbia and they exhibited a high level of interest in the project subject, of course, to final hearings by the National Energy Board of Canada.

The Kitimat Pipe Line will be a Canadian corporation, and we are attempting to structure the company so that equity owners will guarantee debt in proportion of their equity ownership. Trans Mountain and Interprovincial have indicated an interest in owning approximately 30% of the system between them as well as a willingness to guarantee their share of the debt.

At a recent meeting in San Francisco, it was decided that the study group would proceed to develop the necessary information for a permit application. We estimate the total cost of the permit application to be $1.5 million, and seven of the ten study group members have agreed to contribute $150,000 each to finalize the permit application. Barring unforeseen events, we envision making our permit application in the fourth quarter of 1976 and we anticipate that the pipeline can be operational in early 1979 if the permit receives timely approval.

We believe the Kitimat Pipe Line offers significant benefits to Canada. The construction funds and permanent operating jobs will benefit the Canadian economy. Addition of Kitimat volumes to Interprovincial pipeline movements will help to maintain their tariffs at reasonable levels as the decline in Alberta crude reserves reduces shipments of Canadian crude oil. This should help keep prices down for the Canadian consumer. The Kitimat system will give all Canadian refiners west of Montreal access to foreign crude oil through a new deepwater tanker terminal. Canada's current access to tanker crude oil is via Portland, Maine, which can receive only smaller tankers and has congested dock conditions.

In view of the benefits to Canada, the Kitimat group plans to approach the Canadian Government and ask that they assist in developing a means of supplying the Northern Tier refineries during the pipeline construction period. This could involve dedication of an additional 180 to 280 million barrels of Canadian reserves to the export market.

Let us now review the crude oil supply problems of Northern Tier refineries. Undoubtedly, you are aware of the Canadian Government's decision to reduce crude oil exports into the United States in order to conserve their declining reserves and of the adverse consequences this decision will have on Northern Tier refineries.

Attached is a list of Northern Tier refineries that will benefit from the Kitimat Pipe Line. The list is broken down into Priority 1 and Priority 2 refineries, according to FEA classification. In general, Priority 1 refineries do not have pipeline access to significant crude oil supplies except from Canada. Priority 2, while large users of Canadian crude oil, do have pipeline access to alternative crude oil supplies. The total capacity of the Priority 1 group is 421,000 barrels per day. Proposed Canadian exports to this group are 252,000 barrels per day in 1977, 160,000 barrels per day in 1978, and 98,000 barrels per day in 1979. Major investment in a pipeline system is required if these refineries are to continue to operate.

There are a number of reasons why we believe the Kitimat Pipe Line is the best solution to the Northern Tier crude oil supply problems. Let's review some of Kitimat's advantages:

1. Ready access to U. S. crude oil from Alaska

2. An excellent deepwater port that can receive foreign or Alaskan crude oil in very large crude carriers

3. Use of 300,000 to 400,000 barrels per day of spare capacity existing in Interprovincial Pipe Line, thereby minimizing investment

4. If necessary, the Kitimat and Interprovincial systems can be economically expanded to move Alaskan crude oil to Chicago and other Midwest refining centers

5. The Kitimat Pipe Line has many benefits to Canada which should be helpful in maintaining some crude oil supply from Canada during the construction period

6. Kitimat's timing is compatible with the announced Canadian phase-out

7. The Kitimat Pipe Line appears environmentally acceptable. Only four hundred miles of new pipeline right-of-way is required and the Kitimat Harbor is already an industrial location

Kitimat is twelve hundred miles closer to the Persian Gulf than New Orleans or Houston.

Five of the seven companies owning Priority 1 refineries are participants in the Kitimat Pipe Line study group.

A list of the attributes of the Kitimat Pipe Line would be incomplete without explaining how easily the project can serve the Montana Priority 1 refiners. From the table discussed earlier four of the Priority 1 refineries are located in Montana while three are in Minnesota and one is in Wisconsin. The eight refineries are owned

by seven companies - Continental owns two of them. The pipeline map that is included illustrates the relative ease by which Montana can gain access to Kitimat. Note that the Rangeland & Glacier Pipe Line systems run south from Edmonton into Montana, Wyoming, and Colorado. About eighty to one hundred miles of new pipeline construction will be required to enable the Rangeland & Glacier pipelines to be connected to the Kitimat Pipe Line. This new construction is shown as a dotted line. Connecting Kitimat Pipe Line via Interprovincial to Amoco's Mandan, North Dakota, refinery will require minor new construction and this new pipeline is also shown as a dotted line.

This pipeline map presents an overview of what the Kitimat Pipe Line can do for refineries located in the northern part of the United States. The Kitimat Pipe Line could permit refineries from the Puget Sound to Buffalo, and as far south as Colorado, to gain economic access to Alaskan crude oil or foreign crude oil in an environmentally acceptable fashion. In view of the large potential market, the project study group has been debating the merits of a thirty-six inch diameter pipeline instead of the announced thirty inch pipeline. The ultimate capacity of the thirty-six inch system would be 1,100,000 barrels per day instead of the announced 750,000 barrels per day.

The crude oil pipelines serving the northern United States and Canada have been interrelated for many years. For example, the pipeline serving Montreal refineries begins in Portland, Maine, and traverses the entire state. Also, the main pipeline arteries connecting the crude oil production regions in Western Canada with the refining centers in Sarnia and Toronto pass through Minnesota, Wisconsin, Illinois, Indiana and Michigan. As previously discussed, virtually every refinery from Washington to New York has received crude oil via a pipeline originating in Canada. This historic interdependence in crude oil pipeline operations and the recently negotiated pipeline treaty give the Kitimat study group confidence that Canadian-U.S. relations are not a deterrent to the Kitimat Pipe Line.

Following is a brief review of the main alternate pipeline systems suggested as solutions to the Northern Tier supply problem and why we believe Kitimat is the best choice.

First, the Northern Tier Pipe Line project would build a pipeline from the Puget Sound area of Washington to Clearbrook, Minnesota. The advantages of Kitimat Pipe Line over this proposal include:

1. Kitimat requires less than 50% as many new pipeline miles and less than 50% of the investment because it makes use of existing spare capacity in the Interprovincial system and the Rangeland & Glacier systems

2. Because of the magnitude of the Northern Tier project, Kitimat can likely be constructed in a shorter period of time

3. The high investment cost of the Northern Tier system will require a throughput in the range of one million barrels per day in order to provide competitive tariffs. Development of these large volume movements within the time frame requirements of the Northern Tier refineries is unlikely

4. Approval to construct a new terminal at Port Angeles may be difficult to obtain in view of environmental problems in the Puget Sound

A second possibility is a new pipeline system from Cushing, Oklahoma, to the St. Paul area. This system would connect with existing pipelines from the Gulf Coast to Cushing. Two new pipelines recently have been built between the Gulf Coast and Cushing, and there is ample capacity available in that segment. This alternative does not provide access to Alaskan crude oil and it does not help the diminishing supply source of refineries in the Montana-Wyoming area. Also, Houston cannot accommodate very large crude carriers, at least until the Seadock project is completed. Williams Pipe Line Company's existing system can be marginally expanded but to provide sufficient capacity a new system must be built by the refiners or Williams. Economic calculations show that Persian Gulf crude oil can be moved to St. Paul at a lower cost via Kitimat than via Houston and Cushing.

Third, reversing the Trans Mountain Pipe Line is a very prominent alternate to supplying Northern Tier refineries with both Alaskan and foreign crude oil. The Vancouver refineries are not designed to process Alaskan crude oil, and they probably will continue to be supplied with Canadian crude oil from Edmonton. Atlantic Richfield and Trans Mountain are reviewing the possibility of operating the Trans Mountain system on a "yoyo" basis because Trans Mountain delivers all the crude requirements of the Vancouver refineries in about ten days pumping time. If storage were available for the one million barrels of pipeline fill, the line could be reversed and Alaskan or foreign oil could be pumped the remainder of the month. Atlantic Richfield apparently is willing to let Trans Mountain use their Puget Sound refinery dock for unloading tankers. Unfortunately, as in the Northern Tier Pipe Line project, environmental issues associated with increasing tanker traffic in the Puget Sound may represent a signficant impediment to timely development of this project.

It would be conceivable to move Alaskan crude oil to some Northern Tier refineries using the proposed Los Angeles to Midland, Texas, system. However, there probably is insufficient pipeline capacity between Midland and Cushing, Oklahoma. A new system from Cushing north would be required and the economics of this movement to the Northern Tier would be very unfavorable compared to Kitimat Pipe Line. Also, Montana-Wyoming refineries would not be helped by this system.

A fifth alternate that holds high hopes for Northern Tier refiners is expansion of CAPLINE from St. James, Louisiana, to Patoka, Illinois, with

subsequent construction of a new line into Chicago and St. Paul. The Kitimat Pipe Line study group view this as the second most attractive route to solve the Northern Tier supply problem, and they are preparing to pursue this alternate if favorable action is not taken by the Canadian National Energy Board. This alternate could access Alaskan oil via Sohio's proposal, but unfortunately, the North Dakota, Montana and Wyoming refiners could not be served by this system.

Finally, it is important to recognize that Alaskan North Slope crude oil, while welcome as a new domestic supply source, represents a rather difficult crude oil to refine because it is a heavy, high sulfur crude oil that contains large volumes of residual products. Because of these quality problems, there will probably be a large surplus of Alaskan crude oil over and above U.S. West Coast refineries' capability to process it. Some Northern Tier refiners can accommodate Alaskan North Slope crude oil with existing facilities. Others will probably install additional units to permit processing of Alaskan North Slope crude oil if the Kitimat Pipe Line is approved. Indications are that the Kitimat Pipe Line will provide a significant market and transportation capability for Alaskan crude oil.

Section IV - D - Federal Policy Role

This section of your questionnaire poses the hypothetical situation of how the West Coast crude oil surplus should be dealt with on a short and long term basis if Kitimat, Northern Tier, and Sohio are delayed. At least two alternate need some explanation.

First, oil could be shipped thru the Panama Canal in Jones Act tankers. The supply of available Jones Act tankers in early 1978 has been estimated to be sufficient to carry 200,000 to 250,000 barrels per day of the West Coast surplus to the Gulf Coast. During the last half of 1978 and the first quarter of 1979, additional Jones Act tankers now on order will be delivered, and the capability to transport surplus West Coast crude oil should increase to 400,000 barrels per day. Additionally, U. S. flag ships presently in foreign trade service could be given special permission to transport Alaskan oil. While this alternate does represent a short term expedient to the West Coast surplus problem, it should be viewed as nothing more. The movement of oil thru the Panama Canal in small, inefficient tankers would be very expensive and a rather wasteful use of energy in and of itself. Furthermore, moving Alaskan oil to the Gulf Coast will in no way solve the supply problem of Northern Tier refineries. Alaskan oil delivered to the Gulf Coast will not displace crude oil into the Northern Tier becaus transportation systems do not exist to effect such a displacement.

A second, and more logical solution, to the West Coast crude oil surplu problem would be to initiate exchanges with Canada preferably, and Mexico possibly. The Trans Alaskan Pipe Line Bill prohibits Alaskan oil being exported to <u>non-contiguous</u> foreign countries unless the President and Congress make specific findings that it is in the national interest to do so. The act does not preclude Alaskan oil being exchanged with Canada or Mexico, and Presidential or Congressio approval is not required to effect such an exchange. The real obstacle to a Canadia exchange is that no means exists to get large volumes of Alaskan oil into Canada.

Vancouver refineries could take a small volume of Alaskan oil, but they do not represent a complete solution to the problem.

Exchanges with Canada could be effected by involving two countries. Alaskan oil could be traded to the Japanese for Middle East oil delivered to Canada by way of the Portland, Maine pipe line terminal. The Middle East crude oil could then be traded for Canadian oil delivered to Northern Tier refiners. This plan is complicated, but it would allow full production of the much needed Alaskan oil, and it would supply Northern Tier refiners. Obviously, Presidential and Congressional approval would be required for this type of arrangement. It is not practical to consider moving Alaskan oil to eastern Canada literally by way of Panama or Cape Horn.

The West Coast excess crude oil situation is a very serious problem. It is important that government officials recognize the problem now so that appropriate actions can be taken to ensure full Alaskan production as soon as oil can be received at Valdez. We recognize and concur with the current policy objection to selling Alaskan oil in the world market. This action would result in a short term improvement in U.S. balance of payments, but the action would also worsen our dependence on foreign sources of energy. We recommend that the Trans Alaskan Pipe Line Bill be amended to allow for international trading of

Alaskan oil unless such trading results in a net loss of volume available to the U.S. with all such trades to be approved by FEA or some other government agency. The amendment also should stipulate that all Alaskan production be refined and be consumed on the North American continent after such time as pipeline facilities are available to transport Alaskan production to refinery locations east of the Rocky Mountains.

We do not envision a need for legislation to select or to make way for a pipeline solution to the West Coast crude oil surplus. Current forces at work in the marketplace will ensure an efficient and expeditious solution of the problem for the American consumer.

Section V - Cost and Prices

We offer a general observation that should provide a basis for answering each of the issues raised by Question V. Mr. Joseph D. Harnett, Executive Vice President of Sohio, responded under cross examination during Chairman Melcher's Public Land Subcommittee hearing on the transportation of Alaskan oil to the lower 48 states that Sohio would absorb all transportation costs associated with marketing its Alaskan oil. The implication of Mr. Harnett's statement is that Sohio will price Alaskan oil on a delivered basis rather than on a wellhead basis, and the price at a given refinery will be competitive with alternate available crude oil of a similar quality. The wellhead price then would be the actual market price less transportation costs.

Within the allotted response time we have attempted to answer the questions listed below to the best of our ability using the most authoritative source material available. However, it should be noted that we have neither refining nor major petroleum product distribution and marketing facilities located in PAD V, and therefore, we may have devoted less attention to potential future area developments than those concerns and agencies more directly involved. Our projections should be viewed with this notation in mind.

I. West Coast Petroleum Supply

A. Crude Oil

1. Alaska

a) What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans-Alaska pipeline?

July 1, 1977

b) To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

This date has been established by those firms immediately involved in the construction of the project. As of August 15, 75% of the line was complete and 3,007 of the 3,955 weld discrepancies had been resolved. Recent actions by the Alyeska Pipeline Service Company indicate that they intend to take whatever steps necessary to complete the project by the original deadline.

c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

This question could best be answered by those firms with large producing properties and ownership in the pipeline project as they have some degree of production control and access to a greater amount of detailed information with regard to their future plans. However, based on the information publicly available we provide the following estimates of future deliveries.

	M BPD
1977	600
1978	1,200
1979	1,450
1980	1,700
1981	1,900
1982	2,000
1983	2,000
1984	2,000
1985	2,000

FEA Net Energy Outlook adjusted to reflect Trans-Alaska Pipeline

2. West Coast Production

a) What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PADD V)?

1,070M BPD per latest 1976 Bureau of Mines report.

b) What are your best current projections or production of crude oil in PADD V other than

from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

	M BPD
Actual 1975	1,080
1976	1,086
1977	1,137
1978	1,188
1979	1,233
1980	1,303
1981	1,319
1982	1,388
1983	1,359
1984	1,380
1985	1,353

Includes Elk Hills, OCS (50M BPD in 1980 to 200M BPD in 1985), and Cook Inlet (190M BPD in 1975 declining to 122M BPD in 1985). Source - Union Oil

3. Imports

a) What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulphur content).

1975 PADD V IMPORTS
(M BPD)

	Crude	Products	Sulphur Content
Algeria	1		low sulphur
Bolivia	5	UNAVAILABLE	
Canada	164		low and light
Ecuador	53		high
Indonesia	295		low
Iran	105		low
Libya	7		low
Malaysia	5		low
Nigeria	14		low
Oman	1		high
Qatar	11		high
Saudi Arabia	96		high
United Arab Emirates	50		high
Venezuela	44		high
Total	852		

Source BLM Ashland Oil

b) What are your best current projections of crude oil and product imports into PADD V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in question IV A).

Not Available

B. Refinery Capacity

1. What is the current refinery capacity and throughput in PADD V?

Capacity 2,588M BPD

Throughput 2,329M BPD (90% of capacity)
Source FEA

2. What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

	M BPD		
	Capacity	Throughput	
1976	2,588	2,277	88%
1977	2,835	2,552	90%
1978	2,874	2,587	90%
1979	2,906	2,615	90%
1980	2,938	2,644	90%
1981	2,996	2,696	90%
1982	3,056	2,750	90%

1983	3,118	2,806	90%
1984	3,180	2,862	90%
1985	3,243	2,919	90%

Source FEA

3. What part of the current and projected PADD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

	M BPD		
	Total Capacity	Sour Crude Capacity	%
1975	2,357	1,393	59.1%
1976	2,588	1,692	65.4%
1977	2,835	1,914	67.5%
1978	2,874	1,956	68.1%
1979	2,906	1,984	68.3%
1980	2,938	2,012	68.5%
1981	2,996	2,052	68.5%
1982	3,056	2,093	68.5%
1983	3,118	2,136	68.5%
1984	3,180	2,178	68.5%
1985	3,243	2,221	68.5%

Source verbally from FEA

II. West Coast Petroleum Demand

A. What is the current demand for crude oil and refined petroleum products in PADD V?

1975 - 2,211M BPD

B. What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?

	M BPD
1975	2,211
1976	2,295
1977	2,382
1978	2,472
1979	2,567
1980	2,664
1981	2,752
1982	2,842
1983	2,936
1984	3,033
1985	3,134

BOM adjusted for Ashland Oil projected growth rates

III. West Coast Surplus

Assuming that none of the measures indentified in question IV A is implemented:

A. What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V (i.e., the difference between total PADD V production and refinery runs plus addition to stocks)?

PAD V CRUDE SURPLUS/DEFICIT

	Total PADD V Crude Production	Refinery Runs	Crude Surplus (+) Deficit (-)
1976	1,086	2,277	- 1,201
1977	1,437	2,552	- 815
1978	2,388	2,587	- 199
1979	2,683	2,615	+ 68
1980	3,003	2,644	+ 359
1981	3,219	2,696	+ 523
1982	3,388	2,750	+ 638
1983	3,359	2,806	+ 553
1984	3,380	2,862	+ 518
1985	3,353	2,919	+ 434

Note - Assumes no changes in inventories.

B. What are your best current estimates of the PADD V surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PADD V production and refinery runs plus additions to stocks of such crude oil)?

Not available.

TABLE I

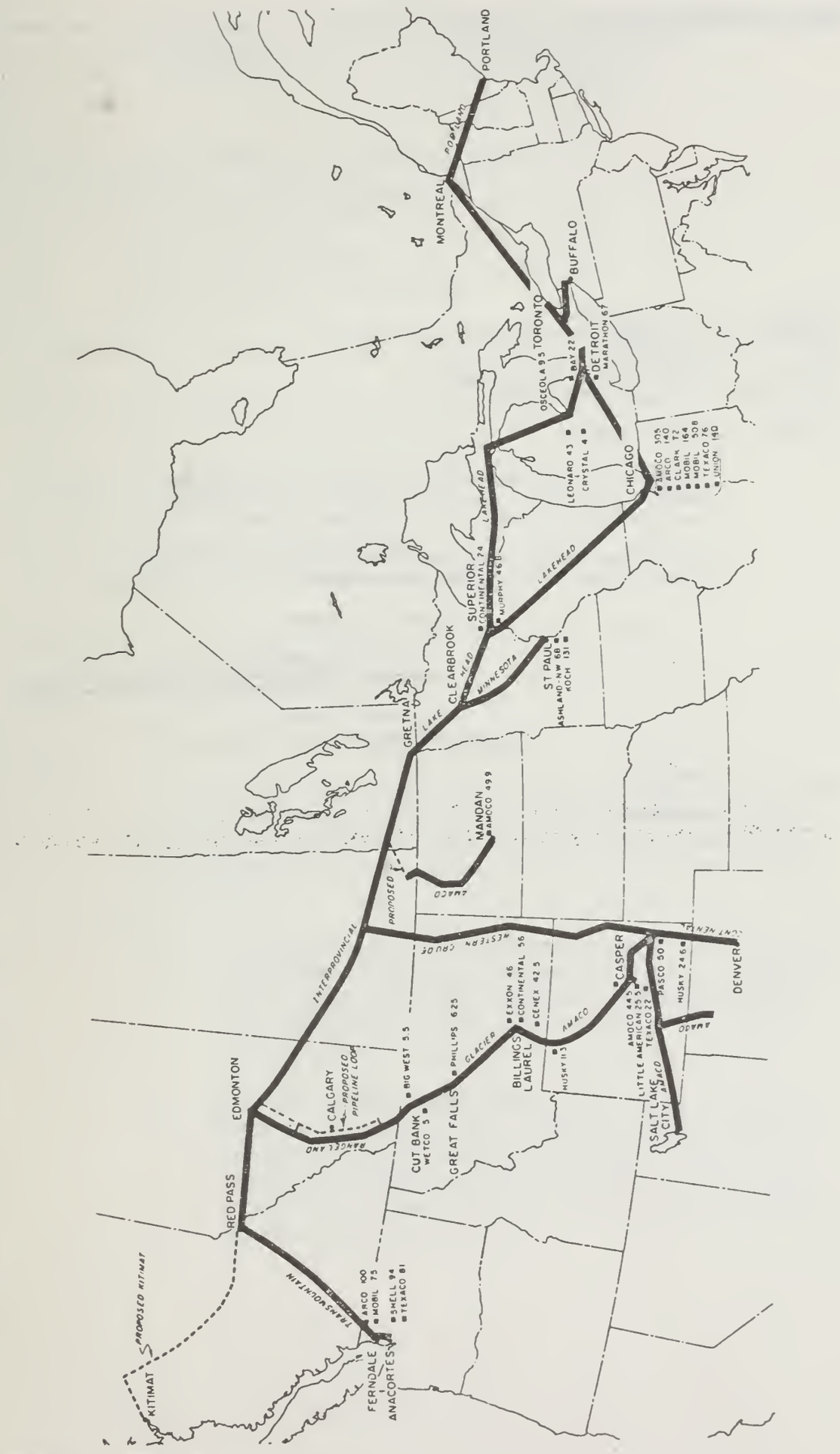
NORTHERN TIER REFINERIES THAT WILL
BENEFIT FROM THE KITIMAT PIPE LINE

FEA PRIORITY 1 REFINERIES

Company	Location	Capacity, B/SD
Big West Oil Co.	Kevin, Montana	5,500
Cenex	Laurel, Montana	42,500
Continental Oil Co.	Billings, Montana	56,000
Exxon	Billings, Montana	46,000
Continental Oil Co.	Wrenshall, Minn.	24,000
Koch Refining Co.	Pine Bend, Minn.	131,905
Ashland Oil - NW Ref.	St. Paul Park, Minn.	68,000
Murphy Oil Corp.	Superior, Wisc.	46,800
		420,705

FEA PRIORITY 2 REFINERIES

Company	Location	Capacity, B/SD
Atlantic Richfield	Ferndale, Wash.	100,000
Mobil Oil	Ferndale, Wash.	75,000
Shell Oil	Anacortes, Wash.	94,000
Texaco	Anacortes, Wash.	81,000
Phillips Petroleum	Great Falls, Montana	6,250
Westco Ref. Co.	Cut Bank, Montana	5,000
American Oil Co.	Mandan, N. D.	49,900
American Oil Co.	Casper, Wyoming	44,500
Husky Oil Co.	Cheyenne, Wyoming	24,600
Husky Oil Co.	Cody, Wyoming	11,300
Little American Ref. Co.	Casper, Wyoming	25,500
Pasco, Inc.	Sinclair, Wyoming	50,000
Texaco, Inc.	Casper, Wyoming	22,000
		589,050


PORTLAND
MONTREAL
PORTLAND
BUFFALO
TORONTO
OSCEOLA 95
BAY 22
DETROIT
MARATHON 67
LEONARD 43
CRYSTAL 43
CHICAGO
AMOCO 305
ARCO 140
CLARK 72
MOBIL 164
MOBIL 558
TEXACO 76
UNION 140
LAKEHEAD
SUPERIOR
CONTINENTAL 24
MURPHY 46
LAKEHEAD
CLEARBROOK
LAKE
HEAD
MINNESOTA
ST PAUL
ASHLAND-NW 68
KOCH 131
GRETNA
MANDAN
AMOCO 499
LAMCO
PROPOSED
INTERPROVINCIAL
WESTERN CRUDE
CASPER
DENVER
EXXON 46
CONTINENTAL 56
CENEX 42.5
PHILLIPS 625
GLACIER
AMACO
AMOCO 44.5
AMERICAN 25.5
TEXACO 22
PASCO 90
HUSKY 246
ODUNA
BILLINGS
LAUREL
HUSKY 11.5
LITTLE
SALT LAKE
CITY
AMACO
EDMONTON
CALGARY
PROPOSED
PIPELINE LOOP
BANGELAND
BIG WEST 3.5
CUT BANK
WETCO 3
GREAT FALLS
RED PASS
TRANSMOUNTAIN
ARCO 100
MOBIL 75
SHELL 94
TEXACO 81
PROPOSED KITIMAT
KITIMAT
FERNDALE
ANACORTES

Butler Associates, Inc. SUITE 600, HARVARD TOWER / 4815 SOUTH HARVARD / TULSA, OKLAHOMA 74135 / 918 743-9855

(Northern Tier)

September 13, 1976

ENGINEERING,
MANAGEMENT SERVICES
AND DESIGN OF
PIPE LINE SYSTEMS
Crude Oil
Natural Gas
Petroleum Products
Liquified Petroleum Gases

Cable BUTLER
Telex 49-23-93
TULSA, OKLAHOMA

Ms. Betsy Moler
Committee on Interior and Insular Affairs
Room 3204
Dirksen Senate Office Building
Washington, D.C. 20510

Dear Ms. Moler:

In accordance with conversations between you and Mr. E. Blake Hastings of my staff, we are forwarding our responses to the questionnaire referenced in the Senate letter of August 23, 1976.

For your information, Butler Associates is the Engineer-Manager of the proposed Northern Tier Pipeline System.

Very truly yours,

Vincent E. Butler
President

VEB:lla

Enclosure

QUESTIONNAIRE
Potential Problems Associated with the Delivery
of Crude Oil from Alaska's North Slope

Responses by Northern Tier Pipeline Company

I. West Coast Petroleum Supply

A. Crude Oil: No response

B. Refinery Capacity: No response

II. West Coast Petroleum Demand

A. Current Demand: No response

B. Current Projections: No response

III. West Coast Surplus

A. Net Surplus: No response

B. North Slope Surplus: No response

IV. Proposed Responses to the Projected West Coast Surplus

A. Proposed Responses

1) Proposed Northern Tier Pipeline

The Northern Tier Pipeline System originates at a deepwater tanker unloading facility at Port Angeles, Washington and extends approximately 1530 miles eastward to Clearbrook, Minnesota. The proposed facilities for the system include the following:

a. A deepwater tanker unloading facility at Port Angeles, Washington capable of handling tankers up to 326,000 dwt in size. Two berths will be constructed initially with provision made for addition of a third berth at a later date.

b. Onshore crude oil storage facilities in the vicinity of Port Angeles, Washington with six million barrels of tankage capacity. Adequate acreage is available to provide for construction of an additional seven million barrels of storage facilities. Total storage capacity equals 13 million barrels.

c. A combination 42-inch and 40-inch diameter pipeline with 21 pumping stations from Port Angeles, Washington to Clearbrook, Minnesota. Ultimate system capacity is approximately 800,000 barrels daily to Clearbrook.

d. Delivery facilities at Clearbrook, Minnesota for distribution of oil into Lakehead Pipeline and Minnesota Pipeline. Delivery facilities will also be provided for connection to existing pipelines serving refineries in the Northern Tier, Midwest and North Central regions of the United States.

The purpose of this proposed system is to provide independent common carrier services for receiving crude oil by tanker from Alaska and foreign sources and transporting the crude oil to Northern Tier refineries now predominantly supplied by Canadian exports as well as providing an alternate source of supply to other refineries now being supplied by domestic and other foreign sources. As shown by the general route map following, the Northern Tier Pipeline system provides access to existing transportation now supplying refineries in the Rocky Mountain, Midwest, North Central and Eastern United States.

2) Proposed Trans Provincial Pipeline: No response

3) Proposed Sohio Project: No response

4) Proposed Panama Pipeline: No response

5) Retrofitting Refineries: No response

6) Central Desulphurization Units:

The Northern Tier Pipeline Company presently has no plans for constructing and operating a desulfurization facility as part of their proposed Northern Tier Pipeline system.

7) Shutting-in of production: No response

8) Export or Exchange Program: No response

B. Status: Northern Tier Pipeline

1) Current Status

Northern Tier Pipeline has made considerable progress in

the development of its proposed pipeline project from Port Angeles, Washington to Clearbrook, Minnesota. The progress made is consistent with that needed to meet an announced completion date of 1979. The work completed since Northern Tier's conception is as follows:

a. A preliminary engineering report and construction cost estimate for the Northern Tier Pipeline system was completed on June 8, 1976. This comprehensive report is the basis for the detailed engineering design which is currently underway for the pipeline and deepwater port facility.

b. Transportation tariffs have been established by the Northern Tier Pipeline Company and are based on volumes that are achievable and acceptable to investors in the project. The tariffs proposed for this system are as follows:

To	From Port Angeles, WA
North Bend	$ 0.11
Glacier Pipe Line	0.51
Butte Pipe Line	0.64
Mandan	0.75
Clearbrook	0.90
Superior/Wrenshall	1.03
Twin Cities	1.07
Chicago	1.18
Marysville	1.22
Buffalo	1.32

c. On July 6, 1976, Northern Tier Pipeline Company made application to the Energy Facility Siting Council of the State of Washington for authorization to construct a tanker unloading facility and storage terminal in the vicinity of Port Angeles, Washington and to construct the pipeline across the state of Washington. This council accepted Northern Tier's application. The council has subsequently prepared a schedule of public hearings in counties which the system traverses. These hearings are presently underway and will be completed during the month of September.

d. Northern Tier has completed a preliminary environmental assessment of the marine terminal and pipeline and is presently developing the environmental impact statement for the State of Washington for submittal to the Energy Facility Siting Council. This environmental impact statement is scheduled for completion by November 1, 1976. Plans are currently underway to commence permit applications and environmental impact statements for the remaining route of the pipeline system located in the States of Montana, Idaho, North Dakota and Minnesota.

e. In August, 1976, a contract was awarded for the aerial photography services required for final route selection. This work will take approximately sixty days to complete.

f. Northern Tier has obtained options to purchase approximately 212 acres of industrially zoned land for the storage facilities and other pertinent installations in the vicinity of Port Angeles.

g. During the next three months, Northern Tier expects to complete its financing program, complete its engineering design, make a final determination of the proposed route on the basis of the aerial and surface mapping currently underway, complete environmental impact statements, and initiate final filing of permit applications.

2) Estimated time for approval and implementation:

a. Federal regulations, proceedings, approvals, permits, etc.

The time required to obtain permits for the Northern Tier Pipeline varies from state to state and between the states and the federal government. For the federal government, however, there is no clearly defined permit process of the Northern Tier project. Northern Tier has made preliminary contacts with the Bureau of Land Management and Forestry Service regarding the appropriate procedures and agency contacts necessary to facilitate any Federal permits which may be required. Further discussions with

these and other Federal agencies are planned in the very near future.

b. State regulations, proceedings, approvals, permits, etc.

The time required to obtain permits for the Northern Tier Pipeline varies from state to state and between the states and the federal government.

In all states, approval of the project will require review of the environmental impacts of the project. In each case, the environmental review process, and thus the permit approval process, begins with submission of environmental information to the appropriate state agency by Northern Tier.

As noted earlier, Northern Tier is preparing its environmental impact statement for the State o. Washington which will be completed November 1, 1976. Plans are currently underway to commence permit applications and environmental impact statements for the remaining route of the pipeline system located in the States of Montana, Idaho, North Dakota and Minnesota.

c. Foreign country regulations, proceedings, approvals, permits, etc.

None. The Northern Tier Pipeline System is totally under political, economic and regulatory control of the United States.

d. Treaty requirements.

No treaty or protocols required.

e. Construction schedules.

Exact construction schedules are dependent upon the time requirements for regulatory proceedings, approvals, and permits. It is noted, however, that once permits are granted to Northern Tier, the construction period will be approximately two years.

3) Direct capital and operating costs.

The estimated capital cost for the facilities proposed for the Northern Tier Pipeline System is approximately one billion dollars. This estimate includes all financing charges as well as escalation considerations due to inflationary increases.

4) Financing arrangements.

Northern Tier Pipeline Company investment bankers, Kidder Peabody & Co., Inc., New York, has developed a detailed financing plan and at this time is in the process of implementing such plan.

5) Refinery and consumer cost: No response

6) Price for North Slope crude oil: No response

7) Net overall national economic costs and/or benefit: No response

8) Self-sufficiency: No response

9) Environmental and safety impacts: No response

10) Any other relevant factors: No response

C. Implementation

Northern Tier Pipeline Company hereby limits its comments to its own proposed project rather than respond to questions concerning other proposed projects.

However, Northern Tier Pipeline Company reserves the right to respond to any comments or responses submitted by proponents of other projects regarding the Northern Tier Pipeline Project, or making comparisons between Northern Tier Pipeline and other projects.

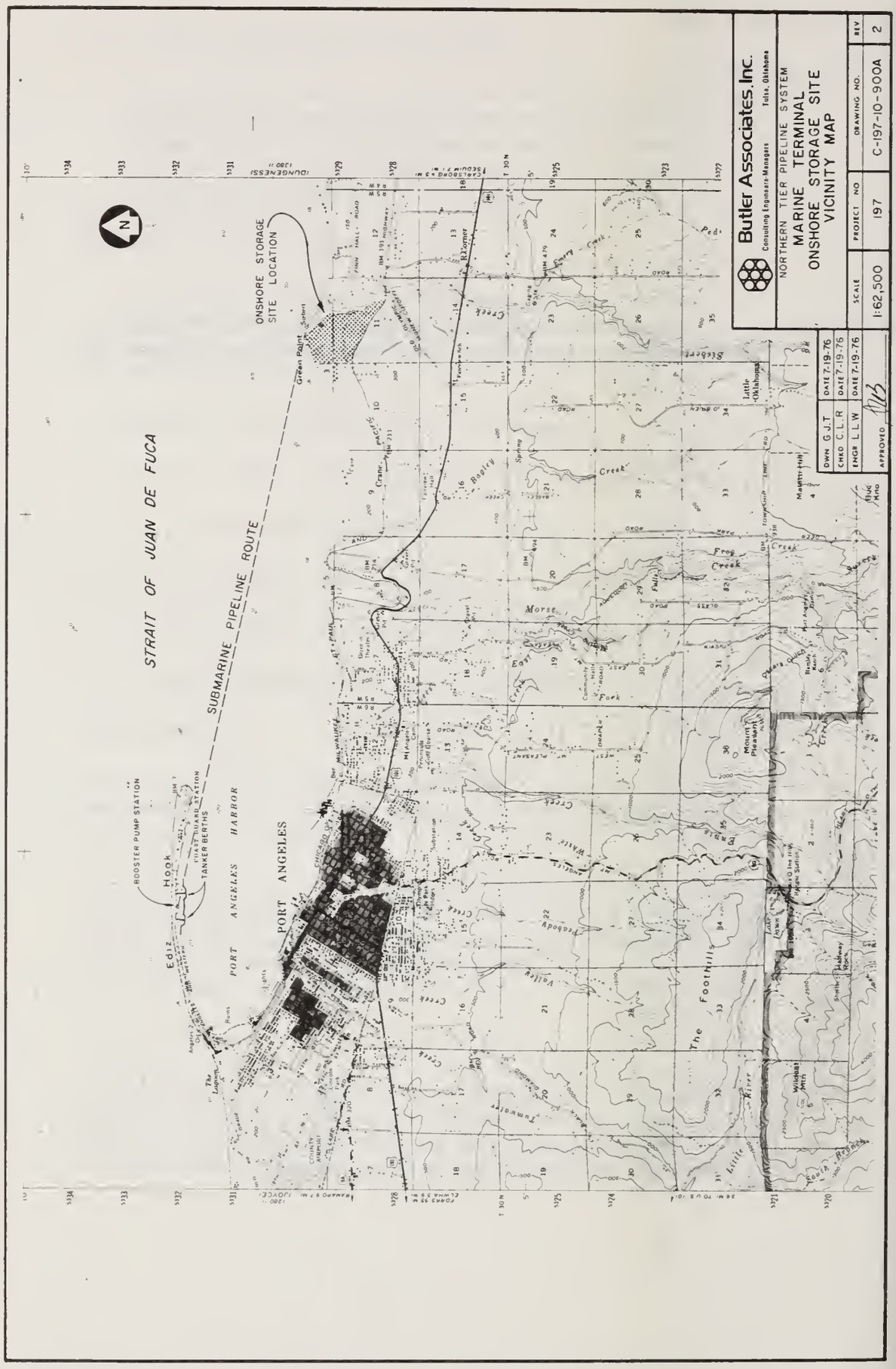
D. Federal Policy

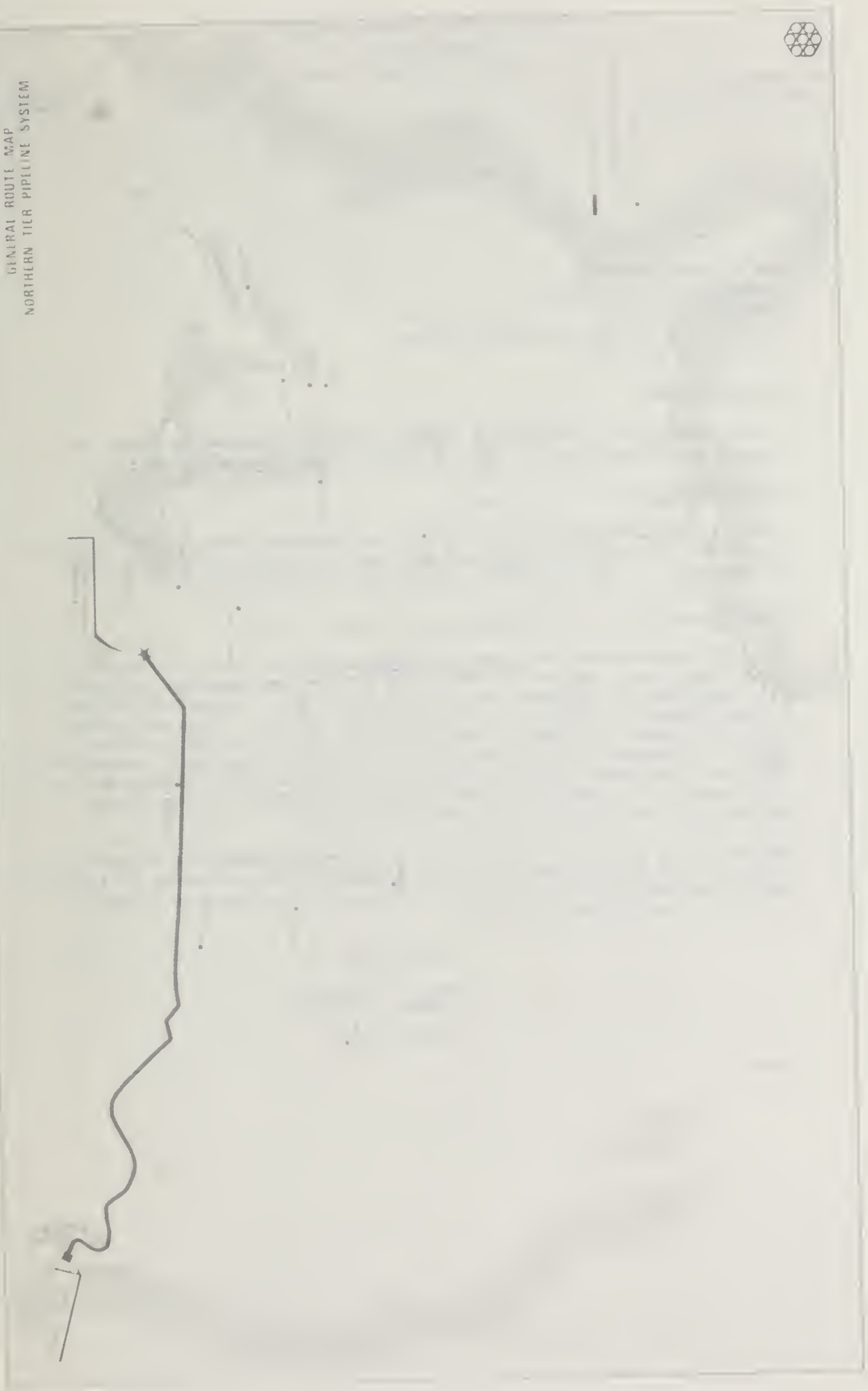
It is important to note that once all regulatory and permitting provisions are met, the Federal Government should give consideration to legislation that will guarantee protection from suits or other legal actions which might cause delays in construction.

V. Costs and Prices

No response

Attachments: General Route Map - Northern Tier Pipeline System
Marine Terminal Onshore Storage Site - Vicinity Map


STRAIT OF JUAN DE FUCA
SUBMARINE PIPELINE ROUTE
ONSHORE STORAGE SITE LOCATION
BOOSTER PUMP STATION
Ediz Hook
COAST GUARD STATION
TANKER BERTHS
PORT ANGELES HARBOR
PORT ANGELES
Butler Associates, Inc.
Consulting Engineers-Managers
Tulsa, Oklahoma
NORTHERN TIER PIPELINE SYSTEM
MARINE TERMINAL
ONSHORE STORAGE SITE
VICINITY MAP
DWN G.J.T
CHKD C.L.R
ENGR L.L.W
APPROVED
DATE 7-19-76
SCALE 1:62,500
PROJECT NO 197
DRAWING NO. C-197-10-900A
REV 2


GENERAL ROUTE MAP
NORTHERN TIER PIPELINE SYSTEM

PORTAL PIPE LINE COMPANY
P.O. DRAWER "L"
MINOT, NORTH DAKOTA 58701

MARK NICHOLAS, MANAGER
DONALD BELL, ASST MANAGER

TELEPHONE
701-852-1087

October 8, 1976

Ms. Elizabeth A. Moler
Professional Staff Member
United States Senate
Committee on Interior and Insular Affairs
Washington, DC 20510

Dear Ms. Moler:

I have received the questionnaire covering problems associated with distribution of North Slope crude oil and respectfully submit the following.

Items I thru III

Portal Pipe Line Company has not conducted an independent study related to these items, and has based its assumptions and conclusions on previously published information.

Items IV and V

The questionnaire sets forth nine (9) different methods for the utilization of North Slope crude. Each has its merits and shortcomings depending upon individual viewpoints. The ultimate answer might well be that a combination of the proposals needs to be effected to best solve the problem. A proposal by Portal Pipe Line Company to provide a method for crude supply to the Northern Tier states is attached. The area considered in the proposal has fewer alternatives than many other areas of the U.S. None of the proposals thus far submitted can be in a position to supply this area during 1977 or 1978. Thus, Tank Train appears to be the only hope to alleviate the problem.

The complexity of the questions does not allow for the preparation of adequate answers in the allotted time frame. Would appreciate your review of the proposal, and if more detailed response is needed, please advise and we will be happy to provide all the information we can.

Respectfully,

Mark Nicholas

Mark Nicholas

MN:kdb

PORTAL PIPE LINE COMPANY

Proposal to Move Crude Oil
West Coast to Northern
Tier Refineries

History

Portal Pipe Line Company is a common carrier pipeline transporting crude oil from various Williston Basin Oil Fields located in North Dakota and Montana to other pipeline systems serving refineries in North Dakota and Minnesota. The Portal system was constructed and became operational in 1962. Available volumes for transportation have always been well below design capacity. For example, an additional 100,000 BPD could be moved east of Minot by adding booster stations to the existing system. Portal has a well maintained and well operated system capable of complimenting transportation of crude oil to Northern Tier States.

Concept

With the announced curtailment of Canadian exports, there will be crude deficits in the Northern Tier states beginning in 1977 with termination of all Canadian exports by 1982. Portal Pipe Line Company proposes movements of crude oil via unit train utilizing the GATX Tank Train cars from the West Coast to proposed terminals at Cut Bank, Montana and Tioga, North Dakota. Portal would provide the following:

Terminal operation on the West Coast,
Tank Train cars, and
Terminal operation at Cut Bank and Tioga.

From the Cut Bank Terminal, the crude oil would move into Glacier Pipe Line Company for delivery to the refineries at Billings-Laurel, Montana. From Tioga, the crude oil would move either into Amoco Pipe Line thence to the Mandan, North Dakota refinery or through Portal to Clearbrook, Minnesota, thence into Minnesota Pipe Line to the Minneapolis, St. Paul refineries. The Lakehead Pipe Line connection also provides potential movements to Northern Michigan, Chicago and New York areas.

This concept has the following advantages:

Could be in operation four to six months after thru-put agreements are finalized.

Protects investment in existing pipeline systems.

Capital risks are at a minimum, and no capital need be risked in a foreign country.

Creates employment opportunity.

Provides immediate relief for crude deficit areas.

Control of oil and the tariff regulations will be in U.S. hands.

Has flexibility to backhaul compatible commodities.

West Coast

Portal proposes to move the crude oil through an existing west coast port and tank farm facility at least until such time as required volumes for Northern Tier states justifies construction of a separate facility. Investigation has determined at least one (1) existing facility that could be easily utilized. This facility is at Port Westward, Oregon on the Columbia River. It has in place the largest tank farm in the state of Oregon, along with associated pier facilities and rail trackage.

Rail Transportation

Portal would either lease or own the Tank Train cars. The decision as to which alternative is most advantageous has not been determined at this point in time.

Burlington Northern Railroad would provide motive power and operate the unit trains. Burlington Northern has many years experience in unit train operation and maintains a fine rail system inter-connecting the proposed terminal sites.

Terminal Facilities

Cut Bank: A Tank Train unloading facility would be constructed and operated by Portal on Burlington Northern property at Cut Bank, Montana. The terminal would have capability to unload a 90-car unit train in four hours. The crude would be pumped from the cars through a meter and directly to the existing Glacier Pipe Line Station.

Tioga: An unloading terminal similar to the Cut Bank facility would be constructed at Tioga, North Dakota. Unloading rates would be the same as at Cut Bank with the crude being moved either to existing Amoco Pipe Line storage or to Portal Pipe Line's station located eight miles south of Tioga.

Each facility would be equipped with an inert gas generator which is needed to supply pressure to the tank train cars causing the crude oil to flow from car to car. This is basically a closed system and no hydrocarbon emissions are vented from the cars to the atmosphere.

Environmental Considerations

It is pointed out that this proposal calls for the maximum utilization of existing facilities, thus reducing the impact that would be felt from constructing new and in many cases duplicate facilities. In transit, the Tank Train cars are isolated and contain a blanket of inert gas, reducing dangers of explosion or fire in the unlikely case of derailment. When unloaded, the cars would contain inert gas again virtually eliminating danger of explosion or fire. These inert gases could be vented through an incinerator at the loading point, thus no hydrocarbon emissions would pollute the atmosphere. This concept would result in less detrimental impact upon

the ecology than any competing system.

Costs

Attention is called to Table 4 - Page 3-73 of the Bonner and Moore Study prepared for the Federal Energy Administration, copy of which is attached. Prices reflected are those estimated upon data presently available.

TABLE 4

TRANSPORTATION COST ESTIMATES FOR BURLINGTON NORTHERN/GATX PROPOSAL

$/bbl	Cut Bank, Montana	Billings, Montana	Minot, North Dakota	Mandan,[2] North Dakota	Clearbrook,[3] Minnesota	Minneapolis, Minnesota	Superior, Wisconsin	Marysville, Michigan
Load (Port Westward)[1]	0.15							→
Variable	1.45	1.45	1.95	1.93	1.95			→
Car Ownership	0.15	0.15	0.21	0.20	0.21			→
Running Gear	0.08	0.08	0.14	0.13	0.14			→
Unload	0.10							→
Pipeline	---	Glacier 0.30	---	Amoco 0.11	**Portal[4] 0.35**	Minnesota 0.52	Lakehead 0.41	Lakehead 0.57
TOTAL without Backhaul	1.93	2.23	2.55	2.62	2.90	3.07	2.96	3.12
TOTAL with Backhaul (30% credit on variable cost)	**1.50**	**1.80**	**1.97**	**2.04**	**2.32**	**2.49**	**2.38**	**2.54**

[1] 35 DWT Tankers. Does not include cost of lighte ing larger tankers.
[2] Unload at Tioga.
[3] Unload at Minot.
[4] Portal will reduce existing $0.55/Bbl tariff.

SOHIO THE STANDARD OIL COMPANY
MIDLAND BUILDING, CLEVELAND, OHIO, 44115

CHARLES E. SPAHR
CHAIRMAN

September 15, 1976

The Honorable Henry M. Jackson, Chairman
Senate Committee on Interior and Insular Affairs
3106 Dickson Senate Office Building
Washington, D.C. 20510

The Honorable Warren G. Magnuson, Chairman
Senate Committee on Commerce
5205 Dickson Senate Office Building
Washington, D.C. 20510

The Honorable Adlai E. Stevenson III
Senate Committee on Commerce
5205 Dickson Senate Office Building
Washington, D.C. 20510

Dear Senators Jackson, Magnuson and Stevenson:

I am enclosing our response to your questionnaire of August 23rd regarding the West Coast crude oil surplus and the alternatives for handling it. I'm pleased that your Committees are concerned about this crude supply situation and I hope the results of your questionnaire will bring you additional insights on the subject.

As I'm certain you are aware, Sohio has been very concerned about this matter since 1974 when it first became apparent that a surplus of crude oil might develop once North Slope production reached the 1,200,000 barrel a day level. I provided information to the Senate Committee on Interior and Insular Affairs during 1974 and discussed Sohio's plans for dealing with the surplus.

Since that time, Sohio has spent a great deal of time and effort in evaluating alternatives and developing a system to handle the problem in a timely, economic and environmentally acceptable manner. I am convinced that the project we have

selected, the West Coast to Mid-Continent Pipeline, is the best method for solving the surplus problem and our responses to your questionnaire reflect this conviction.

Our proposed pipeline from the West Coast to Midland, Texas has three principal advantages. First, it is environmentally superior to any other alternative capable of resolving the surplus. The project uses spare capacity in existing pipelines and provides for development of port facilities in an existing major port. Second, it offers extreme flexibility providing a means of transporting crude oil from the West Coast to a number of major oil refining centers as well as to strategic storage sites. Finally, because Sohio has been working on this project for over two years, committing both time and money to its development, it is the only alternative which can be implemented in a timely fashion to handle the surplus on a long term basis in a manner consistent with the energy goals of this nation.

It's important that we all understand the key energy supply problems that exist. As the replies to your questionnaire will no doubt demonstrate, the cost to the nation of not solving those problems in an efficient and timely manner is very high indeed.

Sincerely,

Charles E. Spahr

CES/jv

Responses By

The Standard Oil Company
(An Ohio Corporation)

To The August 23, 1976, Questionnaire
Of The
Senate Interior and Insular Affairs and
Commerce Committees

Regarding

Potential Problems Associated With The
Delivery of Crude Oil From Alaska's North Slope

- - - - - - - - - - - - - - - - - - - -

QUESTION NO. I

WEST COAST PETROLEUM SUPPLY

A. Crude Oil

1. Alaska

a) What is your best current estimate of the date of first deliveries of North Slope crude oil at Valdez through the Trans Alaska Pipeline?

b) To what extent does this estimate reflect questions now being raised concerning pipeline welds or other potential or anticipated technical delays?

c) What are your best current projections of production and deliveries of North Slope crude oil at Valdez from their commencement for each year through 1985 (taking into account producing capacity in the field, pipeline transport capacity, deliveries within Alaska and use for pipeline fuel)?

2. West Coast Production

a) What is the current production of crude oil in Petroleum Administration for Defense District V (hereinafter PADD V)?

b) What are your best current projections of production of crude oil in PADD V other than from the North Slope for each year through 1985 (taking into account Elk Hills production and the Outer Continental Shelf)?

3. Imports

a) What is the current level of crude oil and product imports into PADD V by country of origin? (Please indicate whether the crude oil imports have relatively high or low sulfur content.)

b) What are your best current projections of crude oil and product imports into PADD V by country of origin for each year through 1985? (State assumptions behind those projections regarding measures identified in question IV A.)

B. Refinery Capacity

1. What is the current refinery capacity and throughput in PADD V?

2. What are your best current projections for refinery capacity and throughput in PADD V for each year through 1985?

3. What part of the current and projected PADD V refinery capacity is capable of processing Alaska crude oil or crude oil of similar grade?

ANSWER NO. I. A. 1. a)

The current estimate for startup of the Trans Alaska Pipeline and first delivery of oil from Prudhoe Bay to Valdez is mid-1977.

ANSWER NO. I. A. 1. b)

This estimate reflects fully all questions currently being raised concerning pipeline welds and all other technical problems which can reasonably be anticipated at this time. However, since many governmental agencies have the ability to suspend construction and delay completion, and since such actions would be completely beyond the control of the owners, no provision for this could be made in the answer to I. A. 1. a) above.

ANSWER NO. I. A. 1. c)

Our current projection of production from the Prudhoe Bay field and delivery of this oil to Valdez via TAPS is shown below for the years 1977 through 1985. These levels assume a Maximum Efficient Recovery for the present Prudhoe Bay field of 1,500 thousand barrels per day (mb/d). It is impossible to make accurate predictions of Maximum Efficient Recovery rates until a history of production exists and approval of the MER is received from the State of Alaska. Therefore, the actual MER may differ from this assumption. Studies thus far indicate that a production rate from the existing Prudhoe Bay field of 1,500 mb/d could be sustained for six to eight years, or, alternatively, 1,200 mb/d could be sustained for a longer period. Pipeline capacity and production from the Prudhoe Bay field and other as yet undeveloped fields in the same area may be increased to as much as 2,000 mb/d by 1982, but no such specific plans now exist. The timing of any such expansion would depend on the timing of the development of other fields and the solution to the West Coast surplus.

Year	Production Using Facilities Presently Under Construction *(mb/d)*	Production Using Facilities Expanded To Ultimate Design Capability *(mb/d)*
1977 (last half)	600	600
1978	1,200	1,200
1979	1,200	1,200
1980	1,200	1,200
1981	1,200	1,200
1982	1,200	2,000*
1983	1,200	2,000
1984	1,200	2,000
1985	1,200	2,000

* Assumes production from fields other than Prudhoe Bay, expansion of TAPS to 2,000 mb/d, and a solution to the West Coast surplus.

ANSWER NO. I. A. 2. a)

The current production of crude oil in PADD V averaged 1,076 mb/d according to the latest full year ~~(U.S.)~~ 1975 Bureau of Mines report, comprised of:

California	882 mb/d
Alaskan Cook Inlet	194 mb/d
Total	1,076 mb/d

ANSWER NO. I. A. 2. b)

We estimate that production in PADD V (excluding Alaskan North Slope) will be about 1,200 to 1,400 mb/d in 1978, comprised of:

California	865 mb/d
Alaskan Cook Inlet	150 mb/d
New Elk Hills	100 - 300 mb/d
New Offshore	100 mb/d
Total	1,215 - 1,415 mb/d

By 1980, we estimate that the Elk Hills production will be at the maximum of the range shown above, and PADD V production (excluding North Slope) will thus be a total of about 1,400 mb/d.

By 1982, current domestic production in PADD V is expected to decline by some 100 mb/d, and the total will thus be about 1,300 mb/d.

California	750 mb/d
Alaskan Cook Inlet	150 mb/d
Elk Hills and New Offshore	400 mb/d

Our estimates include allowances for new offshore discoveries and must, therefore, be interpreted cautiously. We have made no projections of production during the intervening years, nor have we attempted to

forecast beyond 1982 since so many unpredictable variables would have to be considered.

ANSWER NO. I. A. 3. a)

The level of crude oil imported in PADD V for 1975 is shown below according to the Bureau of Mines:

Country of Origin	Relative Sulfur Level	Quantity (mb/d)
Algeria	Low	1
Bolivia	Low	6
Canada	Low	164
Ecuador	High	49
Indonesia	Low	295
Iran	High	106
Libya	Low	8
Malaysia	Low	5
Nigeria	Low	15
Oman	High	3
Qatar	High	11
Saudi	High	91
UAE	High	54
Venezuela	Low	22
Venezuela	High	22
Total Imported		852 mb/d
Total High Sulfur/Sour		336
Total Low Sulfur/Sweet		516

ANSWER NO. I. A. 3. b)

We assume that almost all high sulfur crude oils currently being imported will be displaced by the new domestic sources. Almost all, because certain high sulfur crude oils of particularly light gravities are not replaceable by Prudhoe Bay quality crudes. On the other hand, Prudhoe Bay crude, although considered by many to be a sour crude, has

a lower sulfur content than many of the high sulfur crude oils now being imported. We estimate that additional requirements of low sulfur crude oils beyond current domestic availability (including an allowance for these particular high sulfur crude oils for which Prudhoe Bay crude is not a substitute) will be in the range of 400 to 550 mb/d in 1978. Initially, this quantity will all be imported, but as the maximum use is made of refinery capabilities to refine sour crude, this requirement for sweet crudes will decrease slightly, and over the longer term, to the extent that sweet crude sources are developed domestically in PADD V (for example, from the Stevens Zone of Elk Hills, and any new offshore discoveries), then the portion imported can be expected to decrease.

Net product imports from offshore and other PAD districts into PADD V (including refinery gain) were approximately 190 mb/d during 1975 (Bureau of Mines figures). These net imports are primarily caused by products distributed into the eastern areas of PADD V from refineries in neighboring PAD districts and refinery gains in PADD V. Since none of these is significantly affected by changes in crude oil supply, we anticpate that the net imports will continue at a similar proportion of the total PADD V product market (approximately 8 percent).

ANSWER NO. I. B. 1.

The current refining capacity in PADD V is approximately 2,400 mb/d, according to the 1975 FEA figures. The throughput during 1975 in these West Coast refineries was reported by the Bureau of Mines to be approximately 2,022 mb/d, or 85 percent of capacity (of which 1,967 mb/d was crude oil and the remainder natural gas liquids).

ANSWER NO. I. B. 2.

Our best current projection is that refining capacity in PADD V will increase to approximately 2,800 mb/d in 1978, including existing capacity and that already under construction or in the advanced planning stages. In 1978, West Coast throughputs are estimated to be about 2,300 to 2,400 mb/d. In the long term, it can be assumed that refining capacity will increase in response to petroleum product demand (as has occurred historically). However, because of the lead time involved in refinery plant construction, major expansions for which plans are not yet complete are unlikely to become operational before 1980 to 1982. Thus, in 1980, we would expect capacity to be at the same level as in 1978, but utilized at a higher rate of around 88 percent (2,500 mb/d of crude oil), and that significant additions may be expected thereafter.

ANSWER NO. I. B. 3.

Assuming refinery utilization levels of around 90 percent, we estimate that approximately 1,800 mb/d of the 1978 PADD V refining capacity would be capable of processing Prudhoe Bay quality crude oil. All new refining capacity additions from 1975 onward are assumed to be fully capable of handling sour crudes. (It should be borne in mind that a significant portion of the crude oil currently being produced in California is of Prudhoe Bay quality, and we anticipate that this crude oil will continue to be processed in a part of this capacity.)

QUESTION NO. II

WEST COAST PETROLEUM DEMAND

A. *What is the current demand for crude oil and refined petroleum products in PADD V?*

B. *What are your best current projections for crude oil and refined petroleum product demand in PADD V for each year through 1985?*

ANSWER NO. II A. and B.

We expect that the 1975 demand for 2,211 mb/d of petroleum products in PADD V will increase at approximately 5.5 percent per year to about 2,600 mb/d by 1978. This assumes an increase of about 250 mb/d for residual oil and 140 mb/d for gasoline and other light products. If a 4 to 5 percent per annum growth rate beyond that point is assumed (but many variables make that assumption subject to wide fluctuation) demand would be approximately:

Year	Product Demand *(mb/d)*
1975	2,211
1976	2,300 - 2,400
1977	2,400 - 2,500
1978	2,500 - 2,600
1979	2,600 - 2,800
1980	2,700 - 2,900
1981	2,800 - 3,000
1982	2,900 - 3,200
1983	3,100 - 3,300
1984	3,200 - 3,400
1985	3,400 - 3,600

As indicated on page 6 in Answer No. I. B. 1., refinery throughputs in 1975 averaged 2,022 mb/d. Based on our response to Question No. I. A. 3. b) on pages 5 and 6, we estimate that crude oil demand through 1985 will be about 92 percent of the product demands shown above.

QUESTION NO. III

WEST COAST SURPLUS

Assuming that none of the measures identified in question IV A is implemented:

A. *What are your best current estimates of the PADD V net surplus or deficit of crude oil for each year through 1985 in PADD V (i.e., the difference between total PADD V production and refinery runs plus addition to stocks)?*

B. *What are your best current estimates of the PADD V surplus of North Slope crude oil and crude oil of similar grades for each year through 1985 (i.e., the difference between PADD V production and refinery runs plus additions to stocks of such crude oil)?*

ANSWER
~~QUESTION~~ NO. III. A.

The West Coast sour crude surplus which could result, using our estimates for production, imports, and product demand, is forecasted to be in the range of 300 to 600 mb/d with the TAPS line at 1,200 mb/d throughput and could be 600 to 800 mb/d if the TAPS line were expanded to 2,000 mb/d by 1982 and if sufficient additional production were developed:

Year	Domestic Production	Sweet Crude[1] Imports	Net Product[2] Imports	Product Demand	Sour Surplus
1978	2,400-2,600	300-400	190	2,500-2,600	300-600 mb/d
1982	3,000-3,200	400	250	2,900-3,200	600-800 mb/d

[1]Assuming 100 to 150 mb/d of new domestic supply is sweet.

[2]Includes refinery gains, imports from other PAD districts, and product import/export.

We have no reason to believe that any significant variations to these estimates would occur from stock changes.

ANSWER NO. III. B.

Since all surplus crude is assumed to be of Prudhoe Bay quality, see reply to Question No. III. A. above.

QUESTION NO. IV

PROPOSED RESPONSES TO THE PROJECTED WEST COAST SURPLUS

A. *Proposed responses to deal with the projected surplus of North Slope grades of crude oil on the West Coast have included one or a combination of the following:*

(NOTE: THE UNDERLINING BELOW WAS DONE BY SOHIO. IN THE RESPONSES TO QUESTION NO. IV., ALTERNATIVES 1, 2, and 4 THROUGH 9 ARE REFERRED TO BY THE WORD(S) UNDERLINED; ALTERNATIVE 3 IS REFERRED TO AS THE "MID-CONTINENT" LINE.)

1. *Construction of the proposed Trans-Provincial pipeline from Kitimat, British Columbia connecting with the Inter-Provincial pipeline at Edmonton;*

2. *Construction of the proposed Northern Tier pipeline from Port Angeles, Washington to Clearbrook, Minnesota;*

3. *The proposed Sohio project to convert and reverse an existing El Paso Natural Gas pipeline and build necessary connecting pipelines from Long Beach, California to Midland, Texas;*

4. *Construction of a pipeline across the Isthmus of Panama or across Guatemala to connect tanker routes from Alaska with tanker routes to the U.S. Gulf Coast;*

5. *Use of small tankers through the Panama Canal or VLCC's around Cape Horn to the U.S. Gulf Coast;*

6. *Retrofitting existing District V and/or Northern Tier refineries to run North Slope or comparable grades of crude oil;*

7. *Construction of one or more facilities (at Valdez, Kitimat, Port Angeles, or elsewhere) to desulphurize and raise the gravity of North Slope Crude oil, in order to use it in existing West Coast and/or Northern Tier refineries;*

8. *Shutting in of producing capacity in the field and/or postponement of the increases in pipeline capacity on a short-term basis (pending increases in PADD V crude oil demand to absorb the surplus); and*

9. *Exports or exchanges with Canada, Japan or other countries either on a short-term basis (pending implementation of one or more of the foregoing systems) or on a long-term basis (pending increases in PADD V crude oil demand to absorb the surplus).*

B. *If you have knowledge of these proposals, evaluate and compare the foregoing responses and any other relevant alternatives with respect to:*

1. *The current status of each project or proposal;*

2. *The estimated time for approval and implementation including a description of:*

   a) *any required federal regulatory proceedings, approvals, leases or permits;*

   b) *any required state regulatory proceedings, approvals, leases or permits;*

   c) *any required regulatory proceedings, approvals, leases or permits which must be processed in other countries;*

   d) *any treaty requirements;*

   e) *construction schedules, including if necessary, tanker construction levels.*

3. *Direct capital and operating costs;*

4. *Financing arrangements;*

5. *Refiner and consumer costs of crude oil nationally and by region;*

6. *Wellhead price for North Slope crude oil, cash flow to the operating companies and revenues to the State of Alaska;*

7. *Net overall national economic costs and/or benefit;*

8. *Promotion of the capacity for long-term domestic self-sufficiency;*

9. *Environmental and safety impacts; and*

10. *Any other relevant factors.*

C. *Implementation*

1. a) *Considering the foregoing factors, which of the alternatives or combination of them currently appears on balance to be best?*

   b) *Which appear to be workable and acceptable?*

   c) *Unworkable or unacceptable? (Why?)*

2. a) *Among those alternatives identified as workable and acceptable which are now under active consideration by producers, refiners or others?*

b) *Which have reached the stage of application for necessary certificates, licenses and permits?*

3. *For each of those alternatives identified as workable or acceptable what appear to be most significant critical hurdles to implementation (for example, demonstration of technical or economic feasibility; Federal or State air quality standards; obtaining competent and credible corporate sponsors; throughput commitment; legal authority; financing; Federal approval of required certificates, licenses or permits; foreign country, State or Provincial approvals or certificates, licenses or permits).*

4. *For each of those alternatives identified in IV. A., what is your understanding of the time frame for completion? At what capacity?*

D. *Federal Policy Role*

1. *If none of the pipeline systems listed in IV. A. 1-3 (Kitimat, Northern Tier, and Sohio) is approved and constructed in time to transport any of the anticipated West Coast surplus in PADD V created by North Slope crude oil production, how would you recommend the surplus be dealt with on an interim basis? On a long-term basis? (Please comment specifically upon each of the proposed responses set forth in IV. A. 4-9.)*

2. *What, if any, are the specific policy objections to authorization of temporary crude oil exports pending completion of transportation facilities or other systems for efficient domestic utilization of North Slope crude oil?*

3. a) *Is there a need for Federal legislation to expedite approval and construction of a transportation system or other arrangement to deal with the potential crude oil surplus in PADD V?*

b) *What, if any, constraints should such legislation address?*

ANSWER NO. IV. B. 1.

Current Status of Each Project or Proposal

The current status of the various proposals to solve the West Coast surplus in the long term can be divided into three main groups:

Projects Not Under Serious Consideration As Long Term Solutions

Guatemala
Retrofit
Desulfurization
Shutting In
Exchanges
Panama Canal

Projects in the Planning Stages

Port Angeles
Kitimat

Projects Actually Underway

Mid-Continent

Although exchanges and the Panama Canal alternatives are shown as not being seriously considered as solutions to the long run surplus problem, both may have a role in solving any interim surplus which may result before a long run solution is in place.

The two projects which are in the planning stages, Kitimat and Port Angeles, have done preliminary engineering work but have not yet prepared the necessary environmental impact assessments needed to secure permits.

The Mid-Continent project is proceeding on a schedule that will result in permits being granted during the second quarter of 1977, assuming satisfactory resolution of the air quality issue referred to in Answer No. IV. C. 3. on page 24. The Bureau of Land Management is engaged in preparation of the Environmental Impact Statement and the

California Public Utilities Commission is developing the Environmental Impact Report required by California. The draft versions of both of these documents will be completed and issued during October 1976. Once permits are obtained, the line can be operational within twelve to fourteen months.

ANSWER NO. IV. B. 2.

Estimated Time for Approval and Implementation

Since the surplus is forecast for early 1978, the speed with which the project selected to relieve that surplus can be implemented is very important. Delays in construction or implementation can be due to many causes, but primarily they are related to the time required for engineering and financial planning and for obtaining necessary permits and then the actual physical construction time itself. Shown below is our estimate of the time required to implement these alternatives as a long range solution to the surplus problem:

Project	Time to Plan and Secure Permits	Construction Time Until Project Is Operational	Total
Kitimat	12 - 15 Months	24 Months	36 - 39 Months
Port Angeles	24 - 36 Months	24 Months	48 - 60 Months
Mid-Continent	6 - 9 Months	12 - 14 Months	18 - 23 Months
Guatemala	Unknown	At least 30 Mos.	At least 30 Mos.
Panama Canal*	6 Months	36 Months	42 Months
Retrofit	Could vary widely	24 - 36 Months	At least 24-36 Mos.
Desulfurization	24 - 36 Months	24 - 36 Months	48 - 72 Months
Shutting In	N/A	N/A	N/A
Exchanges	After obtaining necessary Presidential and Congressional approval, actual exchanges could be arranged in a matter of weeks.		

* Time shown is for designing and constructing additional U.S. tankers to use the Panama Canal as the sole, long run solution. Tankers now in existence and under construction are capable of handling a portion of the projected surplus.

The estimate shown for Kitimat is based on information provided by the principals in that project. We have no reason to question it, except to note that the time for permitting is considerably shorter than we would expect if the project were being built in the U.S.

The Port Angeles project would cross extremely environmentally sensitive terrain, and our feeling is that the actual time involved, if the project were to be built, would be at the high end of the range, 60 months.

In all of the pipeline cases, it is assumed that purchase order commitments for major materials are placed in such a fashion so as to assure that construction can be initiated promptly once permits are issued. Unwillingness or inability to make such commitments and the corresponding expenditures well in advance of the receipt of permits introduces a third constraint in the timing sequence which can range to as much as one year.

In the case of both the Guatemala and Panama Canal alternatives, the construction time shown is to build the required number of ships and does not reflect the possibility of other demands on U.S. shipyards which could arise if cargo preference were enacted. In the Guatemala case, the assumption is made that pipeline construction could be completed by the time the ships are ready.

ANSWER IV. B. 3

Direct Capital and Operating Costs

Our best estimate of the direct capital costs, including capitalized interest during construction and operating costs for the various alternatives are shown below:

Project	Capital Costs *($ millions)*	Total Operating Costs *($/barrel)*	Throughput Assumed *(mb/d)*
Kitimat			
New Line to Edmonton	$ 500	$ .85	500
Existing Line - Edmonton to Clearbrook	None	.35	500
Total	500	1.20	500
Port Angeles to Clearbrook	1,500 - 1,750	1.50 - 1.70	800
Mid-Continent to Midland	500	1.00	500
Guatemala	1,000+	2.00	As required
Panama Canal	1,000	2.00	As required
Retrofit)) See below* Desulfurization)			
Shutting In Production	None	N/A	N/A
Exchanges	None	N/A	N/A

* The costs of retrofit and desulfurization would vary widely depending on many factors with which we are not familiar. To our knowledge, no one is pursuing either of these alternatives nor are they considered feasible.

The estimate shown for capital costs for the Port Angeles project is based on an estimate made by Sohio in 1974 for a similar pipeline also in the northern tier and crossing similar terrain. While this estimate is somewhat higher than the estimate made by the project's supporters,

we feel it is realistic nonetheless. Delays in obtaining permits could result in higher costs.

The operating costs are shown on a dollar-per-barrel basis and include capital recovery and a reasonable return on investment. For pipeline projects, the rate shown is an estimated tariff for the total length of the line, except in the case of the Kitimat project where the operating cost shown also includes the tariff on existing line from Edmonton to Clearbrook. For the Mid-Continent project, the operating costs include lease costs on existing gas pipelines. For the Guatemala and Panama Canal alternatives, the rate shown is the additional freight rate from Southern California to the U.S. Gulf Coast. While the tariff on a Guatemala pipeline cannot be determined since no project plans now exist, we have estimated that the total cost of the Guatemala alternative would be competitive with the cost of Panama Canal transit.

ANSWER IV. B. 4.

Financing Arrangements

For the Mid-Continent project and, presumably, the Kitimat Project, financing would likely be arranged in the manner customarily used in building common carrier oil pipelines. Specifically, the projects would be financed using throughput agreements, with cash deficiency guarantees provided by the owner-shippers. In the case of the Port Angeles project, since it is not to be owned by the shippers and is being advanced solely on its income-producing merits, it is not clear to us how financing is to be arranged. It's not reasonable to expect that non-owner shippers would permit their credit to be used for financing purposes.

To the best of our knowledge, no financial arrangements have been made for any of the other proposals.

ANSWER IV. B. 5.

Refiner and Consumer Costs of Crude Oil Nationally and By Region

In general, if left to free market conditions and not otherwise constrained by regulation, Alaskan crude oil will sell in the market at or near the cost of the foreign crude oil that it is displacing. The principal market for Alaskan crude is expected to be the West Coast, where it will replace foreign crude oil primarily from the Persian Gulf. For the portion of the Alaskan crude oil which is transported by one of these alternatives to the Gulf Coast, where the price of Persian Gulf crude is essentially the same as on the West Coast, the cost of transportation must be borne by the seller and will have no effect on refiner or consumer costs. The refiner will not pay additional costs to obtain Alaskan crude oil so long as he has a less expensive alternative. Exchanges which might be arranged, where a barrel of foreign crude is essentially replaced by a barrel of Alaskan crude, would have no effect on the refiner's cost of crude.

The only exceptions to this are the Kitimat and Port Angeles projects. To the extent that these projects are providing crude oil to the northern tier refiners, who will have no other alternative once Canadian oil is no longer available, the cost of transportation will be borne by the refiner. In effect, they will buy Alaskan crude oil in either Kitimat or Port Angeles at a price competitive with foreign oil, and they will pay a tariff to move it to their refineries. This is true whether they purchase

foreign crude and transport it through the line or competitive Alaskan crude and transport it through the line. In either event, the refiner or buyer, instead of the seller, will absorb the tariff.

In any event, whichever alternatives of these nine are to be used, the price any given refiner will pay for crude oil would be essentially the same as it would have been if any other alternative had been used, providing crude oil is available to him through some other means.

ANSWER NO. IV. B. 6.

Wellhead Price for North Slope Crude Oil, Cash Flow to the Operating Companies and Revenues to the State of Alaska

The primary market for North Slope crude oil is expected to be on the West Coast and the wellhead realization for the largest part of Alaskan production will be the selling price in the West Coast market, less the marine freight rate and TAPS pipeline tariff.

Sales east of the Rockies are expected to be made at or about the same price as on the West Coast (i.e., the landed foreign sour crude price) and the seller will have to absorb the extra transportation costs as noted in the answer to Question No. IV. B. 5. Thus, for those sales, the wellhead realization will be lower than for sales on the West Coast by the amount of the extra transportation costs involved which can't be recovered in the market.

The cash flow to the companies would be highest for sales on the West Coast. The cash flow to the companies is reduced in those instances where the companies must absorb extra transportation costs.

Revenues per barrel of production to the State of Alaska are principally affected in the instance where the wellhead realization is

reduced by virtue of the seller having to absorb transportation costs in order to compete.

In the event that an alternative is selected which cannot move the total surplus, or in the event of an alternative which is not capable of doing so in a timely manner, resulting in a production curtailment, the immediate impact on cash flows and revenues to the companies and to the State of Alaska would be substantial. Therefore, either shutting in production and waiting for demand to catch up, or choosing one of the alternatives which would take several extra years to implement would have severe negative effects on the producing companies and on Alaska, when compared with alternatives which can be implemented in a more timely fashion.

ANSWER NO. IV. B. 7.

Net Overall National Economic Costs and/or Benefit

There are many factors which contribute to the net national economic costs cr benefits of the various alternatives. These factors include incremental fuel consumption from different modes of transportation, tariffs paid to foreign countries, and the source of the investment capital if it is foreign. The overwhelming portion of the net national economic cost or benefit, however, is the extent to which a foreign barrel of oil can be displaced by a domestic barrel. All of the proposals essentially accomplish the same result in this regard, except, of course, for the alternative of shutting in production. Proposals which by themselves cannot relieve the entire surplus would have somewhat reduced net economic benefit. There are no doubt some differences among

the exact net national economic benefits of the various proposals, but they are judged to be minor compared with the potential impact of reduced production.

If 500 mb/d of domestic production were shut in because it couldn't be transported to U.S. refineries which could use it, an additional 500 mb/d of foreign oil would be needed. At $13 per barrel, this would increase our yearly payments to foreign countries by about $2.5 billion.

ANSWER NO. IV. B. 8.

Promotion of the Capacity for Long Term Domestic Self-Sufficiency

Any method of moving oil from where it is surplus to an area where it is needed, and doing so without relying in the long term on other countries, promotes the capacity for long term self-sufficiency. Some methods may cost more than others but, disregarding economic factors, all of the alternatives are essentially the same in that respect. Exceptions are shutting in production, which does nothing for self-sufficiency, and those alternatives which place long term reliance on other countries.

ANSWER NO. IV. B. 9.

Environmental and Safety Impacts

The various alternatives can be grouped according to their environmental and safety impacts into three main categories:

No Impact to Very Slight Impact

Shutting In
Exchanges

Low to Moderate Impact

Panama Canal
Mid-Continent
Guatemala
Retrofit

Moderate to High Impact

Kitimat
Port Angeles
Desulfurization

Alternatives which involve only tanker movements require very little in the way of new facility construction, other than the tankers themselves. The Jones Act and existing Coast Guard regulations assure that U.S. tankers meeting high standards of environmental safety would be used. Movement of crude oil through the Panama Canal, and, particularly, the double handling associated with transferring the crude from large Pacific Coast tankers to small tankers for movement through the Panama Canal, increase the exposure for oil spills.

The Mid-Continent project uses 800 miles of existing natural gas pipeline facilities which are no longer needed for gas service and involves only 200 to 250 miles of new pipeline construction. It crosses the arid southwestern United States desert where environmental risk is low. This project involves port facilities within existing harbor facilities. Thus, the impacts associated with construction of a new facility in an area not now subject to tanker traffic can be avoided.

The Kitimat proposal involves construction of some 700 to 750 miles of new pipeline and the use of some existing pipeline in the Jasper National Forest area. The project uses a port with some degree of commercial development already. Because of the relatively mountainous terrain,

additional pipeline construction, and fairly significant additional port development, however, we would rate this project as more environmentally sensitive than the Mid-Continent project.

The Port Angeles alternative involves construction of approximately 1,600 miles of new pipeline. The pipeline would cross the Cascade Mountains, Rocky Mountains, national forests, and a number of rivers and streams. It would also require a new port facility in the Port Angeles area near Puget Sound. Based on our experience in Alaska, we believe that an environmentally acceptable line could be built. Nevertheless, the Port Angeles project has to be considered the most sensitive pipeline project environmentally and the problems associated with obtaining the necessary permits could be a major source of delay.

Building a centralized desulfurization facility would likely involve a new location and would be similar to the problems associated with building a new refinery. To be commercially viable, it would have to be located at Valdez or somewhere along the principal marine route and might involve environmentally sensitive areas. Disposal of the sulfur might present a problem.

ANSWER NO. IV. C. 1. a)

On balance, the best long run solution in our opinion is the Mid-Continent project by itself or supplemented by another project such as Kitimat. Construction of a northern line alone will not be capable of relieving the projected surplus because northern tier refiners can utilize only 150 to 200 mb/d of Alaskan quality oil in addition to local production.

Construction of such a line, however, could eliminate or delay the need to expand the Mid-Continent project if the surplus exceeds the capacity of that line in the future.

ANSWER NO. IV. C. 1. b)

In addition to the alternatives in IV. C. 1. a) above, exchange is the only other alternative considered satisfactory because of the importance of timing.

ANSWER NO. IV. C. 1. c)

The balance of the alternatives are unsatisfactory due to the considerably longer time required to implement them. Shutting in production is unacceptable because of its net national economic cost and the impact on the State of Alaska and the companies.

ANSWER NO. IV. C. 2. a)

Both of the alternatives identified in IV. C. 1. a) as acceptable and workable are actively being worked upon.

ANSWER NO. IV. C. 2. b)

Sohio filed applications with the Bureau of Land Management in July and September 1975. Applications to de-certify the El Paso gas line were filed in June 1975. No other projects have filed Federal applications at this time.

ANSWER NO. IV. C. 3.

The most significant hurdle for the Mid-Continent project at this point is the ambient air quality issue in the Los Angeles basin. Sohio

believes that the Mid-Continent project can be implemented in such a manner that no net increase in emissions will result and the air quality will not be adversely affected. Sohio is working now to demonstrate that belief.

ANSWER NO. IV. C. 4.

Our estimate of the time frame required for each of the alternatives in IV. A. was provided in response to Question No. IV. B. 2. In each case, the capacity of the project was assumed to be as follows:

	Throughput (mb/d)
Kitimat	300 expandable to 500
Port Angeles	800
Mid-Continent	500 expandable to 1,000
Others	N/A

ANSWER NO. IV. D. 1.

Our plan for the interim period until the Mid-Continent project is in place is to begin by using available Jones Act tankers to carry oil through the Panama Canal to U.S. markets where it can displace foreign crude oil. These tankers are capable of handling approximately 200 mb/d of the surplus. Thus, even after using all the available tankers for this purpose, a surplus of 100 to 400 mb/d could remain on the West Coast.

A second group of alternatives relates to handling the portion of the surplus that can't be handled by Jones Act ships. These alternatives include: Crude oil exchanges under which foreign oil controlled by American companies and destined for foreign markets would be delivered

to U.S. ports in exchange for deliveries of Alaskan crude; the use of large foreign flag ships to move crude from Valdez to Cape Horn to the Maritime Provinces or to U.S. ports; or, arrangements with Canada under which Alaskan crude could be exchanged for deliveries of Canadian crude or Canadian controlled crude to U.S. refiners.

ANSWER NO. IV. D. 2.

To our knowledge, there are no specific policy objections to authorization of temporary crude oil exports of North Slope oil providing the authorization is in compliance with the terms covering such export in the Trans Alaska Pipeline Authorization Act.

ANSWER NO. IV. D. 3. a)

In our opinion, there is no need at this time for Federal legislation to expedite approval and construction of a transportation system or other arrangements to deal with the potential PADD V crude oil surplus. However, several states have taken an interest in these alternatives and indicated a possibility of taking actions which might impede their progress. If this occurs, it may be necessary for Federal involvement to lend a national perspective.

ANSWER NO. IV. D. 3. b)

Not applicable.

QUESTION NO. V

Costs and Prices

A. *What is the full anticipated cost of constructing and equipping the Trans Alaska pipeline and terminal facilities to carry up to 1.2 million barrels per day (including interest or funds used during construction)? To 1.6 and 2.0 million barrels per day?*

B. *What are the anticipated crude oil transportation tariffs per barrel from Prudhoe Bay to Valdez, for each year through 1985? (Specify throughput assumptions.) What are the anticipated tanker tariffs from Valdez (a) to Kitimat, (b) to Puget Sound, and (c) to Southern California?*

C. *To what extent, if at all, would a wellhead price ceiling on North Slope crude oil (a) at the composite domestic average price specified by the Energy Policy and Conservation Act, or (b) at the upper tier price established by FEA, be expected to constrain West Coast refinery prices? Refinery prices East of the Rockies?*

D. *If refining prices for North Slope crude oil are determined by prices of alternative supplies (e.g. imports) rather than by FEA price ceilings, will such oil command more than one wellhead price, depending upon its destination or a single wellhead price?*

E. *To what extent, if at all, would the alternative measures identified in Question IV. A. affect average prices of North Slope and similar grade crude oil produced in PADD V (a) at the wellhead, (b) at West Coast refineries, and (c) at refineries East of the Rockies?*

ANSWER NO. V. A.

The current forecasted cost of constructing and equipping the Trans Alaska Pipeline System (not including interest on funds used during construction) to reach throughput capacity of 1,200 mb/d is $7.7 billion. Since each owner company is responsible for providing his share of construction funds, the total capitalized interest during construction for all owners can only be estimated. Currently, capitalized interest expense is estimated at $1.3 billion, bringing the total cost of building and equipping the pipeline to $9.0 billion at the 1,200 mb/d throughput capacity.

Expansion of the line to the 1,600 mb/d level was recently estimated to cost an additional $675 million. Over a year ago, the cost to increase the line from 1,200 mb/d to 2,000 mb/d was estimated at $850 million. These estimates are subject to variation, depending on the timing of expansion. The timing, in turn, depends on ultimate MER of the Prudhoe Bay field, the development of non-Prudhoe sources in northern Alaska, and the ability of the producers to transport, and domestic refiners to utilize, this level of throughput.

ANSWER NO. V. B. (First Question)

The TAPS tariff from Prudhoe Bay to Valdez from startup through 1985 cannot be accurately determined at this time. However, using assumptions that the line will ultimately cost $7.7 billion, as outlined above, assuming acceptable I.C.C. pipeline profit level, and assuming throughput of 1,200 mb/d, the range of tariff is expected to be between $4 and $5 per barrel.

ANSWER NO. V. B. (Second Question)

The tanker costs for moving oil from Valdez to various discharge ports are shown below:

Valdez to Kitimat	$.35 to $.50 per barrel
Valdez to Puget Sound	$.40 to $.55 per barrel
Valdez to Southern California	$.60 to $.80 per barrel

These estimates assume that the oil is carried in long term controlled ships. Cost to move oil in ships acquired in the spot market could vary considerably, reaching levels as much as twice as high, or perhaps even

more, depending on other demand for Jones Act ships at that particular time. Any attempt to forecast spot rates in the future would be highly speculative.

ANSWER NO. V. C.

A wellhead ceiling price established at either the composite domestic average price or at the upper tier price would constrain the market price of Alaskan oil, if that ceiling price, plus the TAPS tariff, plus the marine cost and other transportation cost, is less than the price for foreign crude in the market when the Alaskan crude oil is to be sold. Using today's ceiling prices, foreign oil prices, and cost estimates, neither price level would be a constraint on Alaskan oil, but this could change in the future.

ANSWER NO. V. D.

As noted in the reply to Questions Nos. IV. B. 5. and IV. B. 6., the largest portion of Alaskan oil is expected to be used on the West Coast and, assuming free market conditions, the wellhead realization for oil so used will be approximately the landed cost of foreign sour crude oil on the West Coast, less the marine cost from Valdez to the discharge port and less the TAPS pipeline tariff.

For oil which is not used on the West Coast but is transported to other U.S. markets, the wellhead realization for that oil would be reduced to the extent that the additional transportation costs would have to be absorbed by the seller. In this case, there would be more than one wellhead realization for North Slope crude.

ANSWER NO. V. E.

If the alternative(s) used to relieve the surplus of crude oil on the West Coast is effective, there should be no impact on crude costs at West Coast refineries or at refineries East of the Rockies since foreign crude would be replaced at essentially the same cost to the refiner.

The effect on the wellhead price of Alaskan oil, as discussed in Part D of Question V. above, would depend on the ability of the seller to recover from the buyer the additional transportation costs associated with the alternative.

In the event that an alternative is used that is not capable of relieving the surplus, and no additional means are instituted, then the situation could arise where a glut of Alaskan quality oil on the West Coast could drive prices down for that oil (and comparable quality domestic California production) on the West Coast while other areas of the country remain crude deficient and reliant on foreign imports for a considerable part of their supply.

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